Wabash River Coal Gasification Repowering Project

Annual Technology Report
January – December 1996

Work Performed Under
Cooperative Agreement DE-FC21-92MC29310

For:
The U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
Morgantown, West Virginia

By:

Roy A. Dowd, CHMM
Environmental Supervisor
Wabash River Coal Gasification Repowering Project
444 West Sandford Avenue
West Terre Haute, IN 47885

EXECUTIVE SUMMARY

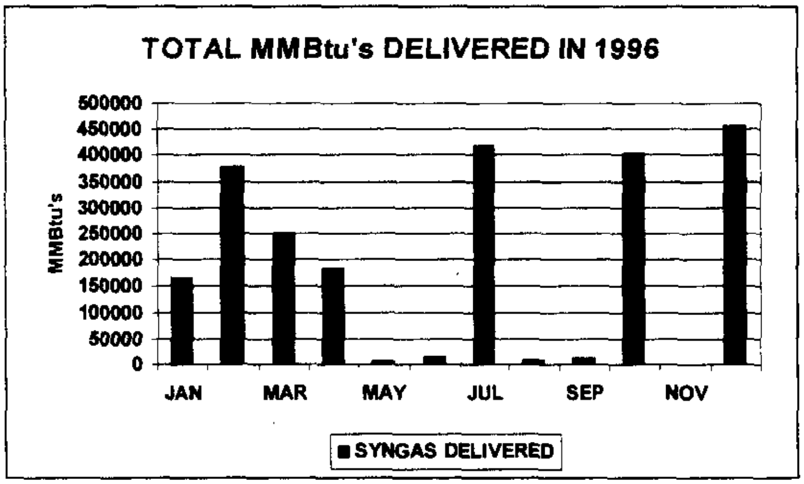
The Wabash River Coal Gasification Repowering Project (WRCGRP, or Wabash Project) is a joint venture of Destec Energy, Inc. of Houston, Texas and PSI Energy, Inc. of Plainfield, Indiana, who have jointly repowered an existing 1950's vintage coal fired steam generating plant with coal gasification combined cycle technology. The Project is located in West Terre Haute, Indiana at PSI's existing Wabash River Generating Station. The Project processes locally mined Indiana high sulfur coal to produce 262 megawatts (net) of electricity.

PSI and Destec are participating in the Department of Energy Clean Coal Technology Program to demonstrate coal gasification repowering of an existing generating unit affected by the Clean Air Act Amendments. As a Clean Coal Round IV selection, the project will demonstrate integration of an existing PSI steam turbine generator and auxiliaries, a new combustion turbine generator, heat recovery steam generator, and a coal gasification facility to achieve improved efficiency, reduced emissions, and reduced installation costs.

Reaching completion in 1995, the Project represents the largest single train coal gasification combined cycle power plant in the United States. Its design allows for lower emissions than other high sulfur coal fired power plants and a resultant heat rate improvement of approximately 20% over the existing plant configuration.

During 1996 the gasification facility operations team focused on the first commercial year of operation, and construction/implementation of plant improvements which included the new Chloride Scrubber System, improved COS Catalyst and improvements to the Dry Char Filtration System. Those major projects were addressed after completing the following initial objectives set in 1996:

- Complete the required performance testing for the Gasification Process
- Complete the required performance testing for the Air Separation Unit
- Complete stack emission testing as required by Destec's (under the name "Gasification Services, Inc." or GSI) "Construction Air Permit"
- Operate the plant and identify those areas that will need to be improved upon during the first commercial year of operation.



1996 marked the first full year of commercial operation after initial start up of the facility on December 1, 1995. The chart at left illustrates the quantity of syngas produced during each month of 1996. Note that the months of February, July, October and December were the highest production months during the year. Also note that there was no production during the month of November due to a major plant maintenance turnaround for equipment repair, inspection, and project implementation. The Gasification Plant Performance Test was completed in early January during a successful 131 hour run on coal at greater than 80% capacity for the duration. During that period the combustion turbine operated on syngas in excess of 100 consecutive hours. In February, the Air Separation Unit (ASU) Performance Test was also successfully completed during a 48-hour test for utility consumption, a 24-hour turndown test and a 12-hour plant capacity test. During the month of March, the gasification facility demonstrated extended operations at 100% capacity, operating in excess of 100 hours at these rates with a daily high of 100.6% and an hourly record of 102.53%.

The Wabash Project achieved several additional operational milestones in 1996, including:

- Completed and complied with all environmental testing for Sulfur Dioxide (SO_2) and Tail Gas Incinerator stack flow (Relative Accuracy Testing or RATA).
- Gasification plant operated on coal 1,902 hours producing 2,769,189 MMbtu's of syngas.
- Verification of design parameters and equipment specification and identification of opportunities to improve the design through projects implementation.
- Identification of an alternate Carbonyl Sulfide Hydrolysis catalyst to increase conversion efficiency and extend catalyst life.
- Installation of a water scrubbing system to remove chlorides from the system thereby reducing downstream failures of stainless steel equipment and catalyst deactivation.
- Combustion turbine operated on syngas for 1,629 hours.

Major milestones and activities projected for 1997 include evaluation of the new project installations, performance monitoring of the Dry Char Recovery System filtration efficiency, continued focus on gasifier operations, and continued demonstration of the commercial viability of the project.

INTRODUCTION

In September 1991 the United States Department of Energy (DOE) selected the Wabash River Coal Gasification Repowering Project (WRCGRP) for funding under the Round IV of the DOE's Clean Coal Technology Program. This was followed by nine months of negotiations and a congressional review period. The DOE executed a Cooperative Agreement on July 28, 1992. The project's sponsors, PSI Energy, Inc., and Destec Energy, Inc., will demonstrate, in a fully commercial setting, coal gasification repowering of an existing generating unit affected by the Clean Air Act Amendments (CAAA). The project will also demonstrate important advances in Destec's coal gasification process for high sulfur bituminous coal. After receiving the necessary state, local and federal approvals, this project began construction in the third quarter of 1993 and commercial operations in the third quarter of 1995. This facility has a planned three-year demonstration period and 22 year operating period (25 years total).

The Wabash River Coal Gasification Repowering Project is a joint venture of Destec and PSI Energy, who have developed, designed, constructed, own and now operate a coal gasification facility and a combined cycle (CGCC) power plant (respectively). This specific coal gasification technology, originally developed by The Dow Chemical Company and owned by Destec, was used to repower Unit 1 of PSI's Wabash River Generating Station in West Terre Haute, Indiana. The CGCC power plant produces a nominal 262 net megawatts (MWe) of clean, energy efficient capacity for PSI's customers. In the repowered configuration, PSI and its customers can additionally benefit because this project can enhance PSI's compliance plan under the CAAA regulations. The project utilizes locally mined high sulfur coal and represents the largest CGCC power plant in operation in the United States. This plant is also designed to significantly lower emissions than most other high sulfur coal fired power plants.

Generate

BACKGROUND INFORMATION

Project Inception and Objectives

Public Law 101-121 provided $600 million to conduct cost-shared Clean Coal Technology (CCT) projects to demonstrate technologies that are capable of replacing, retrofitting, or repowering existing facilities. To that end, a Program Opportunity Notice (PON) was issued by the Department of Energy in January 1991, soliciting proposals to demonstrate innovative energy efficient technologies that were capable of being commercialized in the 1990's. These technologies were to be capable of: (1) achieving significant reductions in the emissions of sulfur dioxide and/or nitrogen oxides from existing facilities to minimize environmental impacts such as transboundary and interstate pollution and/or; (2) providing for future energy needs in an environmentally acceptable manner.

In response to the PON, 33 proposals were received by the DOE in May 1991. After evaluation, nine projects were selected for award. These projects involved both advanced engineering and pollution control technologies that can be "retrofitted" to existing facilities and "repowering" technologies that not only reduce air pollution but also increase generating plant capacity and extend the operating life of the facility.

One of the nine projects selected for funding is the project proposed by the Wabash River Coal Gasification Repowering Project Joint Venture. This proposal (a Joint Venture between Destec Energy, Inc. of Houston, Texas and PSI Energy, Inc. of Plainfield, Indiana) requested financial assistance from DOE for the design, construction, and operation of a nominal 2500 ton-per-day (262 net MWe) two-stage, oxygen-blown, coal gasification combined cycle (CGCC) repowering demonstration project. The project, named the Wabash River Coal Gasification Repowering Project, is located at PSI's Wabash River Generating Station in West Terre Haute, Indiana. The project location and site are shown in Figures 1, 2, 3, and 4 in Appendix B. The demonstration project utilizes advanced coal gasification technology in a commercial repowering setting to repower an existing generating unit affected by the Clean Air Act Amendments of 1990. Sulfur emissions from the repowered generating unit will be reduced by greater than 90%, while at the same time increasing electrical generating capacity over 150%. The project, including the demonstration phase, will last 79 months. The DOE's share of the project cost will be $219 million.

The CGCC system consists of: (See Figures 5 & 5A in Appendix B)

- Destec's oxygen-blown, entrained flow, two stage coal gasifier, which is capable of utilizing high sulfur bituminous coal;
- An air separation unit;
- A gas conditioning system for removing sulfur compounds and particulate;
- Systems or mechanical devices for improved coal feed and all necessary coal handling equipment;
- A combined cycle power generation system wherein the gasified coal syngas is combusted in a combustion turbine generator;
- A heat recovery steam generator.

The result of repowering is a CGCC power plant with low environmental emissions (SO_2 of less than 0.25 lbs/MMbtu and NO_x of less than 0.1 lb/MMbtu) and high net plant efficiency. The repowering increases unit output, providing a total CGCC capacity of nominal 262 net Mwe. The Project demonstrates important technological advancements in processing high sulfur bituminous coal.

In addition to the joint venture members, PSI and Destec, the Phase II project team included Sargent & Lundy, who provided engineering services to PSI, and Dow Engineering, who provided engineering services to Destec.

The potential market for repowering with the demonstrated technology is large and includes many existing utility boilers currently fueled by coal, oil, or natural gas. In addition to greater, more cost effective reduction of SO_2 and NO_x emissions attainable by using the gasification technology, net plant heat rate is improved. This improvement is a direct result of the combined cycle feature of the technology, which integrates a combustion topping cycle with a steam bottoming cycle. This technology is suitable for repowering applications and can be applied to any existing steam cycle located at plants with enough land area to accommodate coal handling and storage and the gasification and power islands.

One of the project objectives is to advance the commercialization of coal gasification technology. The electric utility industry has traditionally been reluctant to accept coal gasification technology and other new technologies as demonstrated in the U.S. and abroad because the industry has no mechanism for differentiating risk/return aspects of new technologies. Utility investments in new technologies may be disallowed from rate-base inclusion if the technologies do not meet performance expectations. Additionally, the rates of return on these are regulated at the same level as established lower risk technologies. Therefore, minimal incentives exist for the utility to invest in, or develop, new technologies. Accordingly, most of the risk in new technologies has traditionally been assumed by the supplier.

The factors described above are constraints to the development of, and demand for, clean coal technologies. Constraints to development of new technologies also exist on the supply side. Developers of new technologies typically self-finance or obtain financing for projects through lenders or other equity investors. Lenders will generally not assume performance and operational risks associated with new technology. The majority of funds available from lending agencies for energy producing projects is for technologies with demonstrated histories in reliability, maintenance costs and environmental performance. Equity investors who invest in new energy technologies also seek higher returns to accept risk and often require the developer of the new technology to take performance and operational risks.

Consequently, the overall scenario results in minimum incentives for commercial size developments of new technologies. Yet without the commercial size test facilities, the majority of the risk issues remain unresolved. Addressing these risk issues through utility scale demonstration projects is one of the primary objectives of DOE's Clean Coal Technology Program.

The Wabash River Coal Gasification Repowering Project was developed in order to demonstrate the Destec Coal Gasification Technology in an environment, and at such a scale, as to prove the commercial viability of the technology. Those parties affected by the success of this Project include the coal industry, electric utilities, ratepayers, and regulators. Also, the financial community, which provides the funds for commercialization, is keenly interested in the success of this project. Without a demonstration satisfying all of these interests, the technology will make little advancement. Factors of relevance to further commercialization are:

- The Project scale (262 net MWe) is compatible with all commercially available advanced gas turbines and thus completely resolves the issue of scale-up risks.

- The operational term of the Project is expected to be approximately 25 years including the DOE demonstration period of the first 3 years. This should alleviate any concerns that the demonstration does not define a fully commercial plant from a cost and operational viewpoint.

- The Project dispatches on a utility system and is called upon to operate in a manner similar to other utility generating units.

- The Project dispatches on a utility system and is called upon to operate in a manner similar to other utility generating units.

- The Project operates under a service agreement that defines guarantees of environmental performance, capacity, availability, coal to gas conversion efficiency and maximum auxiliary power consumption. This agreement serves as a model for future commercialization of the Destec Coal Gasification Technology and defines the fully commercial nature of the Project.

- The Project is designed to accommodate most coals available in Indiana and typical of those available to Midwestern utilities, thereby enabling utilities to judge fuel flexibility. The Project also enables testing of varying coal types in support of future commercialization of the Destec Coal Gasification Technology.

Plant Description

The Wabash River Coal Gasification Repowering Project Joint Venture participants developed and separately designed, constructed, own, and currently operate the syngas and power generation facilities making up the CGCC facility. Coal Gasification technology owned by Destec, is used to repower one of six units at PSI's Wabash River Generating Station in West Terre Haute, Indiana. The Project will operate under a 25 year contact. In the repowered configuration, PSI and its customers additionally benefit because of the role the Project plays in PSI's Clean Air Act compliance plan. The CGCC power plant produces 262 net MWe of clean, energy efficient, cost effective capacity for PSI's customers. An additional economic benefit of the State of Indiana is that the project not only represents the largest CGCC power plant in operation, but also emits lower emissions than other large, high sulfur coal fired power plants.

The gasification process can be described in the following manner: (see Figures 6 and 7 in Appendix B): Coal is ground with water to form a slurry and then pumped into a gasification vessel where oxygen is added to form a hot, raw gas through partial combustion. Most of the non-carbon material in the coal melts and flows out the bottom of the vessel as slag (a black, glassy, non-leaching, sand like material). The hot, raw gas is then cooled in a heat exchanger to generate high-pressure steam. Particulates, sulfur, and other impurities are removed from the gas to make acceptable fuel for the gas turbine. The gasification process by-products, sulfur and slag, will be sold, thus mitigating the waste disposal problems of competing technologies.

The synthetic fuel gas (syngas) is fed to a combustion turbine generator, which produces approximately 192 MWe of electricity. A heat recovery steam generator recovers gas turbine exhaust heat to produce high-pressure steam. This steam, combined with the steam generated in the gasification process, supply an existing steam turbine generator in PSI's plant to produce an additional 104 MWe. The net plant heat rate for the entire new and repowered unit is approximately 9,000 Btu/kWh (Higher Heating Value or HHV), representing an improvement of approximately 20% over the existing unit. The project heat rate is among the lowest of commercially operated coal fired facilities in the United States.

The Destec Coal Gasification process was originally developed by The Dow Chemical Company during the 1970's in order to diversify its fuel base. The technology being used at Wabash is an extension of the experience gained from pilot plants and the full-scale commercial facility, Louisiana Gasification Technology, Inc. (LGTI), which operated from April 1987 until November 1995.

In order to generate data necessary for commercialization, the Joint Venture has chosen a very ambitious approach for incorporation of novel technology in the project. This approach is supported by PSI's desire to have another proven technology alternative available for future repowering or new base load units. Destec desires to enhance its competitive position relative to other clean coal technologies by demonstrating new techniques and process enhancements as well as gain information about operating cost and performance expectations. The incorporation of novel technology in the project will enable utilities to make informed commercial decisions concerning the utilization of Destec's technology, especially in a repowering application.

New enhancements, techniques and other improvements included in the novel technology envelope for the project are as follows:

- **A novel application** of integrated coal gasification combined cycle technology will be demonstrated at the project for the first time – **<u>repowering of an existing coal fired power generating unit.</u>**

- The **coal fuel** for the project **is high sulfur bituminous coal**, thus demonstrating the environmental performance and energy efficiency of Destec's advanced two-stage coal gasification process. Previous Destec technology development has focused on lower rank, more reactive coals.

- **Hot/Dry particulate removal/recycle will be demonstrated at full commercial scale** by the project. Destec's plant, LGTI, utilized a wet scrubber system to remove particulates from the raw syngas.

Other coal gasification process enhancements included in the project to improve the efficiency and environmental characteristics of the system are as follows:

- **Syngas Recycle** provides fuel and process flexibility while maintaining high efficiency.

- **A High Pressure Boiler** cools the hot, raw gas by producing steam at a pressure of 1,600 pounds per square inch absolute (psia).

- **The Carbonyl Sulfide (COS) Hydrolysis** system incorporated at the project is Destec's first application of this technology. This system is necessary to attain the high percent removal of sulfur at the project.

- **The Slag Fines Recycle** system recovers most of the carbon present in the slag by-products stream and recycles it for enhanced carbon conversion. This also results in a high quality slag by-product.

- **Fuel Gas Moisturization** is accomplished at the project by the use of low level heat in a concept different from that used by Destec before. This concept reduces the steam injection required for nitrous oxide (NO_x) control in the combustion turbine.

- Sour water, produced by condensation as the syngas is cooled, is processed differently from the method used at LGTI. This novel **Sour Water System**, used at the project, allows more complete recycling of this stream, reducing waste water and increasing efficiency.

- An oxygen plant producing **95 percent pure oxygen** is used by the project. This increases the overall efficiency of the project by lowering the power required for production of oxygen.

- The **power generation facilities** included in the project incorporates the latest advancements in combined cycle system design while accommodating design constraints necessary to repower the existing Unit 1 steam turbine.

- The project incorporates an **Advanced Gas Turbine** with a new design compressor and higher pressure ratios.

- **Integration between the Heat Recovery Steam Generator (HRSG) and the Gasification Facility** has been optimized at the project to yield higher efficiency and lower operating costs.

- **Repowering of the Existing Steam Turbine** involved upgrading the unit in order to accept increased steam flows generated by the HRSG. In this manner, the cycle efficiency is maximized because more of the available energy in the cycle will be utilized.

The gasification/repowering approach offers the following advantages as compared to other options:

- This is a viable alternative that will add life to existing older units. The primary assumption, however, is that reasonable life exists in the steam turbine to be repowered. If reasonable life exists in the steam turbine, the approach eliminates the need for refurbishment of much of the high wear components of conventional pulverized coal units. Three such items are the boiler, coal pulverizers and high energy piping systems.

- This approach is an alternative for Clean Air Act compliance compared with the traditional scrubber approach. Although space constraints are similar for the installed facility, waste storage requirements are smaller due to salable by-products in lieu of onsite storage of scrubber sludge.

- This approach provides a use for high sulfur coal. This is particularly important in areas such as Indiana, and much of the eastern United States, where high sulfur coal is abundant and provides a substantial employment base.

Project Management

The WRCGRP Joint Venture established a Project Office for the execution of the project. The Project Office is located at Destec's corporate offices in Houston, Texas. All management, reporting, and project reviews for the project are carried out as required by the Cooperative Agreement. The Joint Venture partners, through a Joint Venture Agreement, are responsible for the performance of all engineering, design, construction, operation, financial, legal, public affairs, and other administrative and management functions required to execute the project. A Joint Venture Manager has been designated as responsible for the management of the project. A Joint Venture organization chart is shown as Figure 8. The Joint Venture Manager is the official point of interface between the Joint Venture and the DOE for the execution of the Cost Sharing Cooperative Agreement. The Joint Venture Manager is responsible for assuring that the Project is conducted in accordance with the cost, schedule, and technical baseline established in the Project Management Plan (PMP) and subsequent updates.

Major Activities and Milestones

The Project Cooperative Agreement was signed on July 28, 1992, with an effective date of August 1, 1992. Under the terms of the Cooperative Agreement, Project activities are divided into three phases:

- Phase I Engineering and Procurement
- Phase II Construction and Startup
- Phase III Demonstration

In addition, for purposes of the Cooperative Agreement, the Project is divided into three sequential Budget Periods. The expected duration of each budget period is as follows:

- Budget Period 1 — 10 months
- Budget Period 2 — 27 months
- Budget Period 3 — 39 months

The Project Milestone Schedule is provided in Figure 9 in Appendix B.

Phase I Activities – Engineering and Procurement

Under the provisions of the Cooperative Agreement, the work activity in Phase I (engineering and procurement) focused on detailed engineering of both the syngas and power plant elements of the project which included design drawings, construction specifications and bid packages, solicitation documents for major hardware and the procurement. Site work was undertaken during this time period to meet the overall construction schedule requirements. The Project Team includes all necessary management, administrative and technical support.

The activities completed during this period were those necessary to provide the design basis for construction of the plant, including capital cost estimates sufficient for financing, and all necessary permits for construction and subsequent operation of the facility.

The work during Phase I can be broken down into the following main areas:

- Project Definition Activities
- Plant Design
- Permitting and Environmental Activities

Each of these activities is briefly described below. All Phase I activities were complete by 1993.

Project Definition Activities

This work included the conceptual engineering to establish the project size, installation configuration, operating rates and parameters. Definition of required support services, all necessary permits, fuel supply, and waste disposal arrangements were also developed as part of the Project Definitions Activities. From this information the cost parameters and projects economics were established (including capital costs, project development costs and operation and maintenance costs). Additionally, all project agreements necessary for construction of the plant were concluded. These include the Cooperative Agreement and the gasification services agreement.

Plant Design

This activity included preparation of design and major equipment specifications along with plant piping and instrumentation diagrams (P&ID's), process control releases, process descriptions, and performance criteria. These were prepared in order to obtain firm equipment specifications for major plant components, which established the basis for detailed engineering and design.

Permitting and Environmental Activities

During Phase I, applications were made and received for the permits and environmental activities necessary for the construction and subsequent operation of the project. The major project permits included:

- Indiana Utility Regulatory Commission – The state authority reviewed the project (under a petition from PSI for a Certificate of Necessity) to ensure the project will be beneficial to the state and PSI ratepayers. The technical and commercial terms of the project were reviewed in this process.

- Air Permit – This permit details the allowable emission levels for air pollutants from the project. It was issued under standards established by the Indiana Department of Environmental Management (IDEM) and the United States Environmental Protection Agency (USEPA) Region V. This permit also included within it the authority to commence construction.

- NPDES Permit – This National Pollutant Discharge Elimination System permit details and controls the quality of waste water discharge from the project. It was reviewed and issued by the Indiana Department of Environmental Management. For this project it will be a modification of the existing permit for PSI's Wabash River Generating Station.

- NEPA Review – The National Environmental Policy Act review was carried out by the DOE based on project information provided by the participants. The scope of this review is comprehensive in addressing all environmental issues associated with potential project impacts on air, water, terrestrial, quality, health and safety, and socioeconomic impacts.

Miscellaneous permits and approvals necessary for construction and subsequent operation of the project included the following.

- FAA Stack Height/Location Approval
  Controlling Authority: Federal Aviation Administration

- Industrial Waste Generator
  Controlling Authority: Indiana Department of Environmental Management

- Solid Waste

- FCC Radio License

- Spill Prevention Plan

- Wastewater Pollution Control Device Permit
  Controlling Authority: IDEM

Phase II Activities – Construction

Construction activities occurred in Phase II and included the necessary construction planning and integration with the engineering and procurement effort. Planning the construction of the project began early in Phase I. Separate on-site construction staffs for both Destec and PSI were provided to focus on their respective work for each element of the Project. Construction personnel coordinated the site geotechnical surveys, equipment delivery, storage and lay down space requirements. The construction activities included scheduling, equipment delivery, erection, contractors, security and control.

The detail design phase of the project includes engineering, drawings, equipment lists, plant layouts, detail equipment specifications, construction specification, bid packages and all activities necessary for construction, installation, and startup of the project.

Performance and progress during this period was monitored in accordance with previously established baseline plans. There were no Phase II activities conducted during this period.

Phase III Activities – Demonstration Period

Phase III consists of a three year demonstration period. The operation effort for the project began with the development of the operating plan including integration with the early engineering and design work of the project. Plant operation input to engineering was vital to assure optimum considerations for plant operations and maintenance and to assure high reliability of the facilities. The operating effort continued with the selection and training of the operating staffs, development of the plant operations manuals, the coordination of the startup with the construction crew, planning and execution of plant commissioning, the conduct and documentation of the plant acceptance test and continued operation and maintenance of the facility throughout the demonstration period.

Phase III activities are intended to establish the operational aspects of the project in order to prove the design, operability and longevity of the plant in a fully commercial utility environment.

Budget Periods

For ease of administration, the Project is divided into three budget periods with expected durations of:

- Budget Period 1 9 months
- Budget Period 2 26 months
- Budget Period 3 39 months

Budget Period 1 activities include pre-DOE award and project definition tasks, preliminary engineering work, and permitting activities. Budget Period 2 activities include detailed engineering, procurement, construction, pre-operations training tasks, and startup. Budget Period 3 activities include the three-year demonstration period. The budget period costs were originally projected and revised as follows:

	Original	Revised
Budget Period 1 DOE Share	$43,175,801	$21,864,591
Budget Period 2 DOE Share	$102,523,632	$144,934,842
Budget Period 3 DOE Share	$52,300,567	$52,300,567
Total	$198,000,000	$219,100,000

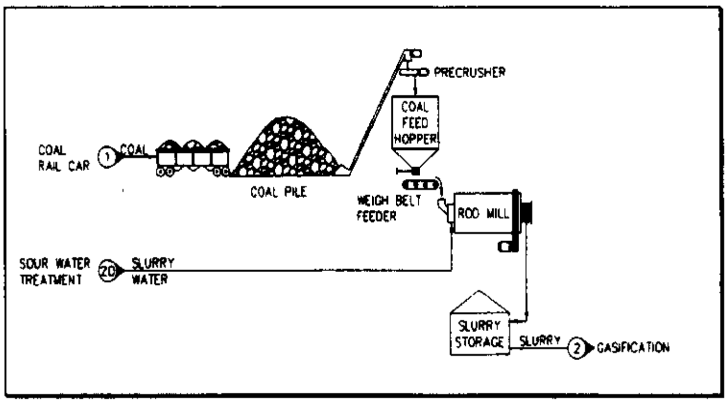
ACTIVITIES DURING 1996

A current Project schedule, indicating milestone dates and current status, is provided as Figure 10.

1996 Phase III Activities – Demonstration Period

The plant processes are broken down by area to better describe the activities during 1996 and focus on the accomplishments and areas identified for improvement. Each area is preceded by an illustrated representation of the process along with a general process description.

COAL PREPARATION AND SLURRY AREA



The diagram at left depicts the process of coal slurry preparation. PSI has the responsibility of delivering coal and transporting it to the feed hopper. Coal enters the feed hopper then is fed to the rod mill via a weigh belt feeder. In 1996 all of the coal processed originated from the Hawthorne mine in Indiana. The coal is mixed with limestone (approximately 2%) at the mine site, which is added as a fluxing agent to enhance slag flow characteristics in the gasifier. Limestone addition is not necessary for lower ash fusion coals. Treated water recycled from other areas of the gasification process is added to the coal at a controlled rate to produce the desired slurry solids concentration of approximately 62%. The use of a wet rod mill reduces potential fugitive particulate emissions from the grinding operations. Collection and reuse of water within the gasification process minimizes water consumption and effluent wastewater volume.

The slurry is then stored in an agitated tank, which is large enough to supply the gasifier needs during forced rod mill outages. Most expected maintenance requirements of the rod mill and storage tank can be accomplished without interrupting gasifier operation.

All tanks, drums, and other areas of potential atmospheric exposure of the product slurry or recycle water are covered and vented into the tank vent collection system for vapor emission control. The entire slurry preparation facility is paved and curbed to contain spills, leaks, wash down, and rain water. All runoff will be carried by a trench system to a sump where it will be pumped into the recycle water storage tank to be reused in the coal slurry preparation system.

Primary coal characteristics, which effect operation of the gasifier include the following:

- Ash Content
- Sulfur
- Carbon
- Hydrogen
- Nitrogen
- Oxygen

The following tables illustrate the average values for these constituents in 1996 while also outlining the variability that was encountered during the year:

COAL IN HOPPER ANALYSIS		COAL ANALYSIS (DRY)		HEATING VALUE	
1st Quarter					
% Moisture	**15.05**	% Carbon	**69.93**	Btu/lb - as received	**10,587**
% Ash	**13.34**	% Hydrogen	**4.61**	Btu/lb - dry basis	**12,532**
% Hydrogen	**5.26**	% Nitrogen	**1.61**		
% Nitrogen	**1.43**	% Sulfur	**2.33**		
% Fixed Carbon	**70.99***	% Chlorine	**.03**		
% Sulfur	**2.42**	% Ash	**13.49**		
2nd Quarter					
% Moisture	**14.31**	% Carbon	**70.48**	Btu/lb - as received	**10,722**
% Ash	**11.52**	% Hydrogen	**4.51**	Btu/lb - dry basis	**12,512**
% Hydrogen	**4.51**	% Nitrogen	**1.38**		
% Nitrogen	**1.38**	% Sulfur	**2.46**		
% Fixed Carbon	**42.81**	% Chlorine	**.03**		
% Sulfur	**2.11**	% Ash	**13.44**		
3rd Quarter					
% Moisture	**14.77**	% Carbon	**69.96**	Btu/lb - as received	**10,801**
% Ash	**13.63**	% Hydrogen	**4.50**	Btu/lb - dry basis	**12,439**
% Hydrogen	**4.83**	% Nitrogen	**1.33**		
% Nitrogen	**1.29**	% Sulfur	**2.44**		
% Fixed Carbon	**41.51**	% Chlorine	**.03**		
% Sulfur	**2.11**	% Ash	**13.60**		
4th Quarter					
% Moisture	**14.6**	% Carbon	**70.43**	Btu/lb - as received	**10,822**
% Ash	**13.31**	% Hydrogen	**4.6**	Btu/lb - dry basis	**12,449**
% Hydrogen	**4.8**	% Nitrogen	**1.49**		
% Nitrogen	**1.5**	% Sulfur	**2.44**		
% Fixed Carbon	**41.5**	% Chlorine	**.04**		
% Sulfur	**2.2**	% Ash	**13.3**		

*Analytical error is presumed due to the statistical variation between this analysis when compared to the three other quarters.

Laboratory analysis of slurry constituents for 1996 is fairly consistent on a day-to-day basis. The following represents an average concentration of the primary constituents analyzed for the 4th quarter and is representative of slurry quality for 1996. Raw analytical data, generated over the past year, is included in the proprietary binder of the 1996 Environmental Monitoring Plan report for 1996. Analyses (except % Solids) indicate dry percent by weight.

% Carbon	**68.15%**
% Hydrogen	**4.67%**
% Nitrogen	**1.38%**
% Sulfur	**2.38%**
% Solids (Slurry fed to gasifier)	**62.60%**
% Ash	**14.00%**

Ash components identified through ICP-AES* analysis was:

% Aluminum (as Al_2)	**18.71%**
% Calcium (as CaO)	**9.87%**
% Iron (as Fe_2)	**14.70%**
% Potassium (as K_2O)	**2.74%**
% Magnesium (as Mg)	**1.42%**
% Manganese (as MnO)	**.05%**
% Sodium (as Na_2)	**.52%**
% Silica (as SiO)	**50.98%**

Inductively Coupled Plasma - Atomic Emission Spectrometer

Incoming coal fed to the rodmill is sampled via an automated sampling system. The samples are analyzed and compared to determine variability and corresponding gasifier operating parameters. During 1996, weather conditions contributed to two major mechanical failures of this automated sampling system. First, heavy snowfall resulted in a wet, sticky, coal supply, which caused plugging problems with the sampler. To rectify this problem, mechanical scrapers and vibrators were installed during the first quarter. With the additional installation of a non-stick coating to the inlet crusher chute in the second quarter, overall system reliability improved. The second problem resulted from coal dust during dry periods. Coal dust, dispersed by air movement generated by the system components, tended to collect around the pulleys of the belt conveyor and impede conveyor movement. To correct this problem, additional seals were installed in the system, which limited air movement thereby limiting the amount of dust and reducing the number of failures in this system. During periods when the mechanical samplers were out of service, operations personnel hand sampled the coal to ensure feedstock consistency.

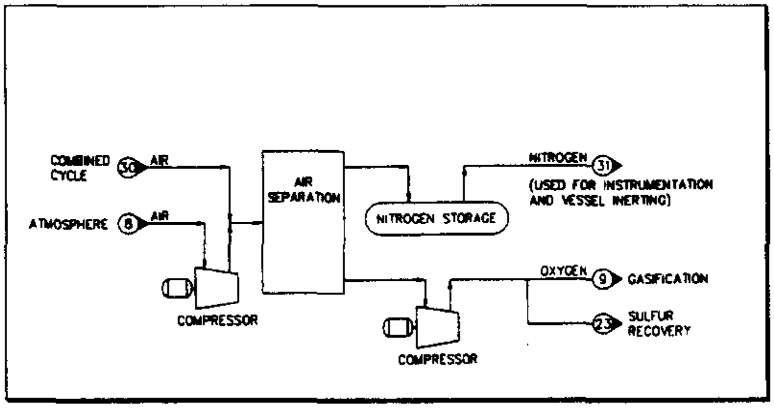
The rod mill is designed to crush the coal to a desired particle sized distribution to ensure stable "slurryability" and optimum carbon conversion in the gasifier. In the third quarter of 1996 it was identified that the rod mill rod charge was insufficient to generate the optimum grind to ensure consistent slurry concentrations. This problem was identified when large coal particles were found in the check valves of the positive displacement pumps utilized for feeding coal slurry into the second stage of the gasifier. These check valves were examined when the positive displacement pumps started to demonstrate flow variability under normal operation. Subsequent analysis of particle size distribution indicated that there was a significant increase in the distribution of larger particles, which warranted the addition of rods to the rod mill. Following an original rod charge of 609 rods for startup, an additional 30 rods were added to the rod mill in July. Three sizes of rods were utilized in this initial operation. Wear rate of the rods were within the manufacturer specifications for the number of hours of operation. Operation of the pumps returned to normal after this change was made. It should be noted that particle size distribution is only utilized as a diagnostic tool for rod mill operation. Specific distribution ratios have not been identified as having either a positive or negative effect on gasifier operation as long as the slurry maintained a solids content of approximately 62%.

Areas of excessive erosive wear were identified throughout the slurry handling system during the year. Control of erosion in the slurry handling area is critical to continued operation and will be carefully monitored throughout the life of the facility. Erosive and corrosive wear affected centrifugal slurry forwarding pumps, stainless steel pipe fittings, the inlet chute to the rod mill and bent and straight piping in the slurry handling system. Where possible, hardened metal internal coatings were placed in the system while, in some cases, metallurgy had to be changed or re-evaluated to improve equipment life. Slurry handling performance will continue to be improved as more operational hours are obtained on the system and analysis of performance is done.

In 1996 a total of over 184,380 tons (as received) of coal were processed through the rodmill. Slurry fed from the slurry feed tank to the gasifier accounted for approximately 4,341,382 MMBtu's with an average Btu value (dry) of the Hawthorne coal of 12,483 Btu/lb. The following table illustrates the quarterly usage of coal feed stock in 1996:

1996	"As Received" Coal Feed	MMBtu
1st Quarter	64,920	1,627,204
2nd Quarter	19,352	488,158
3rd Quarter	31,327	697,612
4th Quarter	68,781	1,528,408
Total	**184,380**	**4,341,382**

AIR SEPARATION UNIT (ASU)



The Air Separation Unit (ASU), depicted at left, contains: an air compression system; an air purification and cryogenic distillation system; an oxygen compression system; and, a nitrogen storage and handling system. Atmospheric air is compressed in a centrifugal compressor then cooled in a chiller tower to approximately 40 degrees F. The cooled air is then purified through molecular sieve absorbers where atmospheric contaminants (H_2O, CO_2, hydrocarbons, etc.) are removed to prevent these contaminants from freezing during cryogenic distillation. The dry, carbon dioxide-free air is separated into 95% purity oxygen, high purity nitrogen, and waste gas in the cryogenic distillation system. The gaseous oxygen is compressed in a centrifugal compressor and fed to the gasifier. Liquid nitrogen (LIN) is also produced in the distillation system with a portion being vaporized for use as gaseous nitrogen in the gasification system and the balance being stored for use during ASU plant outages.

During the first quarter of 1996, and before performing initial capacity testing of the ASU, a production shortfall of nitrogen was identified. Air Liquide engineers re-evaluated the design and recommended an important change to enhance nitrogen production. The change involved the installation of a new heat exchanger designed to recover the refrigeration lost during the vaporization of nitrogen for high-pressure gaseous nitrogen production. The original design used steam energy to vaporize and heat the LIN stream to 60 degrees F for continuous delivery to the gasifier systems. The new exchanger allows more cooling of inlet air to the distillation column, resulting in higher production of product nitrogen.

One negative side effect of the new exchanger was that the airflow to the main heat exchanger was reduced, causing liquefaction of the waste nitrogen to occur upstream of the exchanger. This condition is similar to the detrimental effects of condensed water in a steam turbine. A follow-up project was required to correct this side effect.

An existing gaseous high-pressure oxygen recycle stream was introduced into the main exchanger to remove excess refrigeration from the waste nitrogen upstream of the expander. The cooled, high-pressure oxygen stream is then expanded and liquefied prior to being returned to the low-pressure distillation sump. This prevents waste nitrogen from liquefying, thus eliminating potential damage in the expander. Capturing the refrigeration in this manner, along with the addition of the new exchanger, results in higher nitrogen production. It should be noted that even with these projects, the ASU never achieved the performance guarantees for LIN production.

Even though the ASU is capable of meeting contractual obligations for oxygen at the required purity, nitrogen peak consumption within the gasification island still exceeded design capability of the ASU. This required additional liquid nitrogen to be trucked into the facility at additional costs. Process engineers continued to identify potential sources for conservation throughout the year resulting in a decrease in demand. Nitrogen conservation improvement projects, identified during the fourth quarter of 1996, are scheduled to be implemented near the end of the first quarter of 1997.

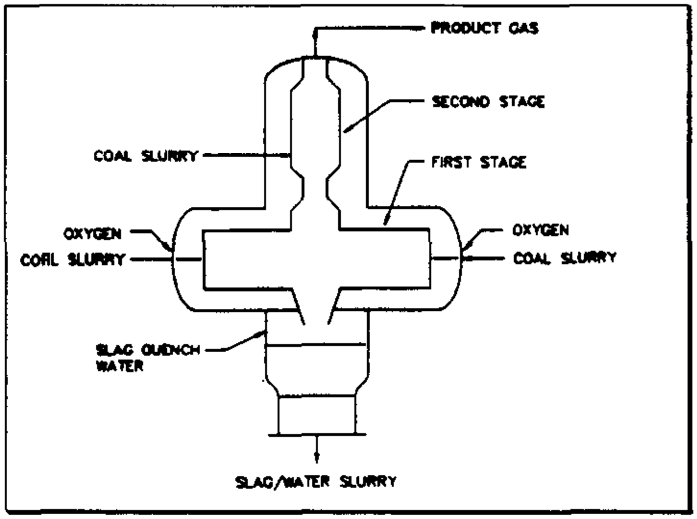
Additional minor issues addressed in the ASU in 1996 included:

- A gradual reduction in flow rate from the liquid oxygen pumps during the second quarter created concern over system reliability. Inspection of the pumps and related equipment revealed that the suction strainers had been improperly installed during construction resulting in excessive particulate build-up within the pumps. Following total pump overhauls within the quarter, performance has increased to design specifications.

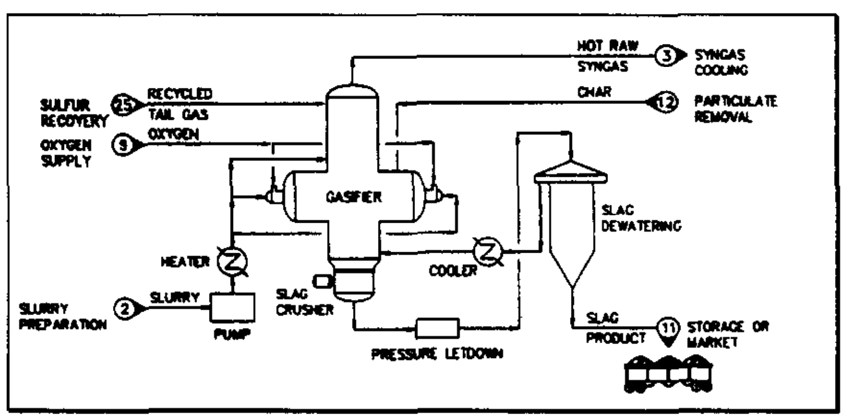
- A manufacturer's inspection in September uncovered a design flaw on the absorber bed sequencing valves. Failure of the valve bushings had been responsible for numerous valve failures in the second quarter. The manufacturer agreed to produce one set of modified valves with a new bushing design. Additional valves of this type in the system will be modified on a set schedule over the next 18 months.

- In December, the main air compressor surged and shut down due to a failure of the 3rd stage guide vane controller. The guide vanes went to the closed position after a rupture of a connector attached to the 3rd stage actuator. This failure caused a four-day interruption in syngas delivery to repair the actuator and restore gasifier operation. No long term negative effects to the compressor were observed as a result of this compressor surge.

GASIFICATION AND SLAG HANDLING

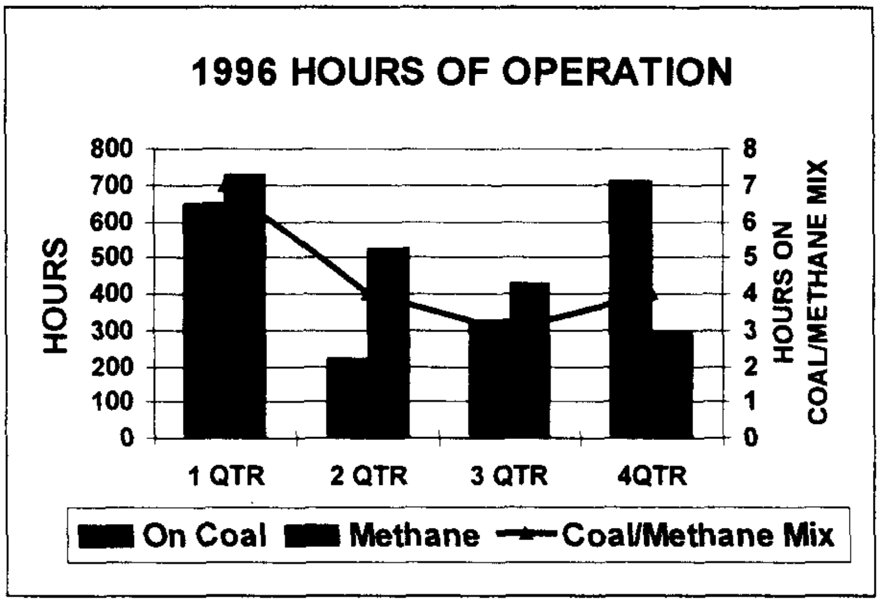


The Destec gasifier consists of two stages; a slagging first stage, and an entrained flow, non-slagging second stage. The first stage is a horizontal, refractory lined vessel in which coal slurry and oxygen are combined in partial combustion quantities at an elevated temperature (nominally 2500 degrees F) and pressure (400 psia). Dry particulate (char) filtered from the raw sygnas downstream of the gasifier is also recycled to the first stage gasification process. The oxygen and coal slurry are fed to the gasifier and atomized through two opposing mixing nozzles once the vessel has been adequately preheated on natural gas (methane) operation. Oxygen feed rate to the mixers is carefully controlled to maintain the gasification temperature above the ash fusion point, thereby ensuring good slag removal. Produced synthetic gas (syngas) consists primarily of hydrogen, carbon dioxide, carbon monoxide and water vapor. Sulfur in the coal is converted primarily to hydrogen sulfide with a portion converted to carbonyl sulfide. Both sulfur species are removed in downstream processes. Mineral matter in the coal forms a molten slag, which is continuously tapped from the gasifier. The second stage is a vertical refractory lined section in which additional coal slurry is reacted with the hot syngas stream exiting the first stage. This additional slurry serves to lower the temperature of the gas exiting the first stage to 1900 degrees F by vaporization of the slurry and endothermic reactions. The coal undergoes de-volatilization and pyrolysis thereby generating more gas at a higher heating value. No additional oxygen is added to the second stage. The partially reacted coal (char) and entrained ash is carried overhead with the gas. Natural gas (methane) is utilized for preheating the gasifier. No product syngas is generated for PSI's consumption during the pre-heat process while in methane operations.



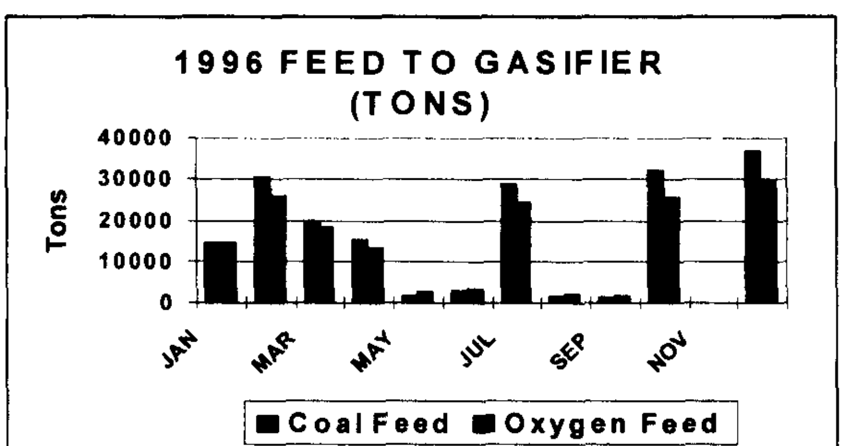
Slag flows continuously through the tap hole of the first stage into a water quench bath, located below the first stage. The slag is then crushed and removed through a continuous pressure let-down system as a slag/water slurry. This process of continuous slag removal is compact, minimizes overall height of the gasifier structure, eliminates the high-maintenance requirements of problem-prone lock hoppers, and completely prevents the escape of raw gasification products to the atmosphere during slag removal.

The slag slurry leaving the pressure let down system flows into a de-watering bin. The bulk of the slag will settle out in this bin, while the water overflows a weir at the top of the bin to a settler in which the slag fines are settled and removed. The clear water gravity flows out of the settler and is pumped through heat exchangers where it is cooled as the final step before being returned to the gasifier quench section. De-watered slag is loaded into a truck or rail car for transport to market or its storage/disposal site located on the south end of the Wabash River Generating station. The fines slurry from the bottom of the settler is recycled to the slurry preparation area. The de-watering system contains de-watering bins, a water tank, cooler and water circulation pump. All tanks, bins, and drums are vented to the tank vent collection system to limit fugitive emissions.



During GSI's operational campaigns in 1996, the gasifier operated on coal 1,902 hours. During heat-up operations, the gasifier operated on methane and a blend of coal/methane for over 1,990 hours (1,972 hours on methane, and 18 hours on a coal/methane mix). It must be reiterated that syngas generated during heat-up operations is not suitable for use as fuel for the combustion turbine and that coal/methane mix is simply a measure of transition from methane heat up to coal operation. Methane operations indicated in the graph above, indicate methane and coal/methane mix hours for heat up of the gasifier and associated equipment and the transition onto full coal operations.

Coal feed to the gasifier totaled over 180,000 tons for 1996 and oxygen feed from the ASU to the gasifier totaled in excess of 160,000 tons. This material feed was utilized in the production of over 2,769,600 MMBtu of syngas. Byproduct slag produced from the process totaled approximately 23,288 tons.



Three critical areas of concern in the gasifier system were identified in 1996 that were run limiters or represented potential reductions of equipment service life. Those three areas were:

- Burner Longevity
- Insulating Brick Life
- System Ash Deposition

In the first quarter of 1996, the plant experienced 3 failures of slurry burners on the first stage gasifier. Investigation revealed that all three failures were similar in nature and were attributed to coal slurry backing into the oxygen space in the burner during the transition to coal operations. Valve sequence timing modifications were completed to prevent recurrence. No similar failures occurred during the remainder of 1996. In the fourth quarter, a newly designed offset burner was evaluated for its effectiveness in reducing deposition while at the same time increasing burner efficiency. Initial results from the burners were inconclusive. A significant reduction in ash deposition was observed downstream of the gasifier; however, the carbon content in the slag was elevated causing increased slag production. This indicated that a higher portion of the carbon in the coal is not being converted to syngas. It was initially surmised that increased carbon conversion was a benefit to be derived from the offset burners. It was noted that no refractory wear occurred as a consequence of using the offset burners. Offset burner evaluation is still underway by studying varying angles of offset and will be addressed in future annual reports if investigation is ongoing. Destec's Engineering group is targeting a 2,000 hour life burner for this application and will be evaluating design and metallurgy changes in 1997.

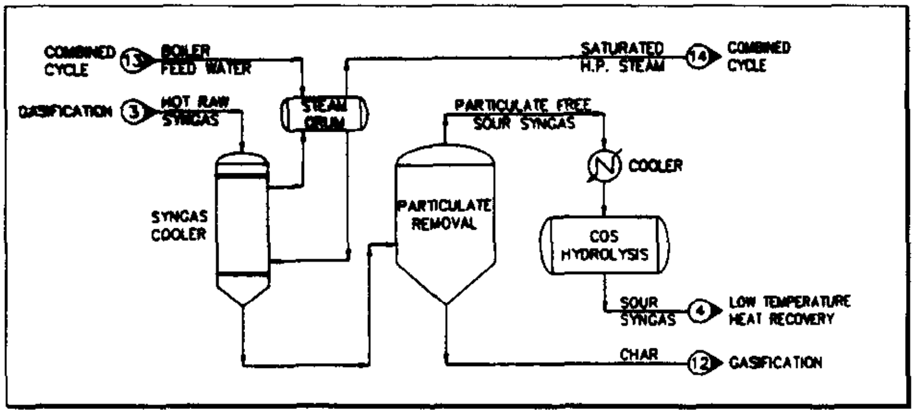
During routine inspections of the refractory lining, it was noted during the third quarter that the wear rate of the current lining in the 1st stage gasifier was significantly greater than anticipated. Core sampling of the lining indicated a failure associated with the bond matrix of the hot face brick. An alternate hot face brick test panel was placed in the transition area between the first and second stage of the gasifier and is currently under evaluation. During the third quarter, a new high-density brick was tested in the exit piping from the second stage gasifier. Previous use of the brick in other areas indicated that sticky ash particles were less prone to attach to the surface of the brick. The results showed promising reductions in ash deposition from previous brick. During the November outage, all the brick in the second stage outlet pipe was replaced with this high-density brick to further reduce ash deposition. Evaluation of this material will continue into 1997.

Deposition occurring in the second stage gasifier and continuing through the high temperature heat recovery unit (HTHRU) has created difficulty in maintaining operation and extends scheduled shutdowns due to the need to remove deposits. Plugging of the boiler tubes from spalled deposits increased equipment downtime due to the time required to remove the deposits. Minor changes have occurred through 1996, from varying operational temperatures in the gasifier and associated equipment, to changes in the type of brick in the system. The rate of ash deposition is also proportional to the number of thermal cycles (full load or partial load trips) experienced in the system.

In 1996 there were 53 separate trips of the gasifier off of coal operation which contributed to ash deposition and subsequent spalling of these deposits. With increased run time on the gasifier, increased operational experience will be gained and more reliable equipment operation achieved reducing the number of thermal cycles on the gasification system and subsequently reducing the potential for system deposition problems.

One minor problem has been noted in this system during 1996 and that involved the failure of the reactor water-cooled nozzle system. During normal operation, boiler feedwater flows in a closed loop, at 450-500 psig, through the water cooled nozzles and is then cooled through heat exchange with cooling tower water. Make-up water for this system is supplied by an 1800 psig system from PSI. In October, plant operation was terminated due to a piping failure in the reactor water-cooled nozzle system. This resulted in deficient flow to all of the nozzles, which subjected them to higher than normal operating temperatures. The piping failure is suspected to have been triggered by a water leak internal to the gasifier. System water loss is compensated by make up from the 1800 psig system. Due to the temperature and pressure of the 1800 psig system, excessive flashing occurred upon entry into the water-cooled nozzle system creating excessive velocity and vibration, ultimately causing a piping failure at a downstream thermocouple location. To prevent recurrence, the thermocouple has been moved upstream of the boiler feed water tie-in to minimize its exposure to the severe conditions during boiler feed water make up. Also, the boiler feed water line size has been increased to allow for higher volumetric flow of flashed boiler feed water. All of the water-cooled nozzles in the system were inspected for damage that may have resulted from the loss of cooling. No further failures to this system have occurred in 1996, but we will continue to monitor this system in 1997.

SYNGAS COOLING, PARTICULATE REMOVAL AND COS HYDROLYSIS

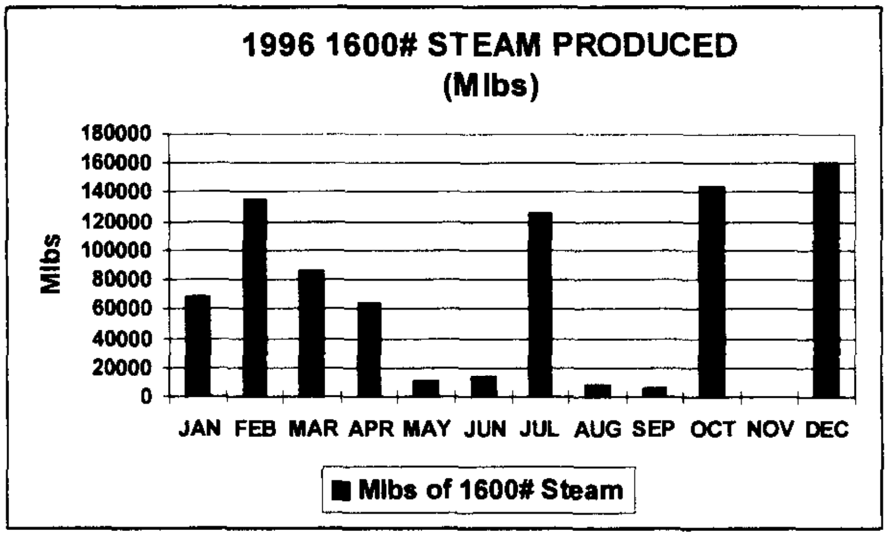


The gas and entrained particulate matter exiting the gasifier system is further cooled below 1900 degrees F in a firetube heat recovery boiler system where saturated high pressure steam is produced. Steam from this high temperature heat recovery system is super heated in the gas turbine heat recovery system for use in power generation.

The raw gas leaving the high temperature heat recovery unit passes through a barrier filter unit to remove the particulates. The recovered particulates are recycled to the first stage of the gasifier. The particulate-free gas is cooled further before proceeding to the carbonyl sulfide (COS) hydrolysis unit.

COS is present in the hundreds of ppm concentration range and is not removed as efficiently as Hydrogen Sulfide (H_2S) by the Acid Gas Removal (AGR) system; therefore, in order to obtain a high sulfur removal level, the COS is converted to H_2S before the sour syngas enters the AGR. This is accomplished by catalytic reaction of the COS with water vapor to create hydrogen sulfide and carbon dioxide. The hydrogen sulfide formed is removed in the AGR section and the carbon dioxide continues on with the raw syngas to the turbine.

Steam production, as shown in the graph at right, tracks the operational run history of the gasifier. Total 1600 psig steam production for 1996 was approximately 726 million pounds.



HIGH TEMPERATURE HEAT RECOVERY UNIT (HTHRU): Deposition in the HTHRU and associated equipment was of prominent concern in 1996. As discussed in the gasification system analysis, thermal cycles of the gas path were a leading contributor to HTHRU plugging due to spalling of ash deposits in upstream equipment and piping. During the first quarter, the plant had to be shut down on two occasions due to high differential pressure across the HTHRU. At high differential pressures the velocity of the gas in the boiler tubes is sufficient to cause erosion due to particulates in the gas. Solids large enough to become lodged in the tubes allow the smaller particles to plug the tube and also cause unacceptable high gas velocity in the partially plugged tubes. Based on operational experience, a differential pressure increase of 2-3 psi can cause excessive velocities in the tubes.

Coal operation was again suspended in the second quarter due to high differential pressure across the HTHRU. The cause of the high differential pressure was again isolated to solids carryover from upstream equipment. This occurred after more than 130 hours of coal operation on the system. Subsequent cleaning allowed operations to put the unit back on line but the system again plugged after only 24 hours of operation. The cause for the rapid plugging of this unit was the result of multiple failures of redundant thermocouples measuring second stage reactor outlet temperatures. High temperature operation in this area resulted in sticky ash particles reaching the boiler tubes and depositing within them.

To help control ash deposition of the tubes of the HTHRU, a boiler inlet screen was designed to eliminate large particles from reaching the inlet of the boiler tubesheet. The inlet screen was installed early in the third quarter (July). Due to the highly corrosive nature of the syngas, a coupon rack of various metallurgy's was installed with the screen to aid in determining the optimal screen material. Coupon testing continued throughout the remainder of the year and into 1997 to evaluate the suitability of the materials of construction of this screen. During a subsequent equipment inspection in the fourth quarter, the screen showed some pluggage due to ash deposition; however, the screen still had significant area open to flow and the screen itself showed little sign of degradation or wear. Additionally, plugging of the HTHRU tubes was significantly reduced. Evaluation of this screen, and other design and operational changes to control ash deposition will be monitored during 1997.

DRY CHAR FILTRATION: After the conclusion of the early January 1996 outage, the Dry Char Filtration System operated well for the rest of the quarter and had no adverse impact on syngas production. This was an improvement from initial operating experience and indicated that previous design changes completed late in 1995 were a step in the right direction. The one significant negative aspect of the system's performance was a gradual blinding of the filter elements as evidenced by a continuous increase in differential pressures. The rate of blinding was slow enough that it did not limit plant capacity during the quarter.

In early February, 48 hours of production was lost due to a piping failure in the Dry Char Recycle System. The recycle system is used to remove fine char and ash from the syngas stream and recycle it back to the first stage of the gasifier. In this system, raw syngas (with entrained char and ash) first enters two parallel primary filter units after exiting the HTHRU. The char is filtered from the gas stream forming a cake on the exterior of the candle filter. The candle filters are arranged in clusters of 42 elements, which are pulse cleaned one cluster at a time. The cake is removed by periodic back-pulsing with high pressure recycle syngas. After the cake is dislodged from the filter, it drops, aided by gravity, to the bottom of the conical shaped outlet of the filter unit where it is drawn from the vessel by ejectors and recycled back to the gasifier. Several design improvements were made to the char recycle ejectors and downstream piping to alleviate the rapid wear rate seen in those pieces of equipment. These improvements were primarily in the materials of construction within this system. Subsequent inspections of ejectors and piping revealed essentially zero additional material loss after implementation of these improvements.

Problems with the Dry Char Filtration System caused the plant to be taken off coal operation on two occasions during the second quarter. The first occurred in late May after only 6 hours of coal operation. Failure of gasket seals, internal to the primary filter vessels, allowed char to bypass the primary filters and eventually plug the secondary filters so that they could no longer be effectively pulse-cleaned. The secondary filter system is designed to handle small leakage from the primary filters and to provide an indication of primary filter leakage. The gaskets failed due to insufficient gasket compression. Investigation revealed that an alternate gasket was being used due to the unavailability of the preferred gasket. The gaskets were replaced with the preferred gaskets and the system operated for 22 hours before failing again.

Although difficult to prove, it is suspected that the combination of changes to the system's operating parameters and perhaps an undetected problem with a pulse gas valve on one of the filter clusters were the root cause of this subsequent failure. The pulse gas nozzles had been modified during the late April outage in an effort to enhance the effectiveness of the pulse cleaning system at the increasingly higher filter differential pressures being caused by element blinding. To offset the resulting increase in pulse gas consumption, which causes lower pulse gas pressures and ineffective cleaning of the filters, the duration of the pressure cleaning pulse was reduced to a value similar to what was used previously. The shorter pulse was unable to effectively clean the filters at their current higher resistance.

Observations within the vessels during the outage subsequent to the second failure revealed that the filters in several clusters were "bridged" (i.e., the spaces between the elements were packed with char) and that several filter elements were broken. It was surmised that the bridged elements were caused by ineffective back-pulse due to the change to the shorter duration pulse, and the pulse duration was therefore increased to the pre-May 1996 value. The broken elements were likely caused by the bridging, or could possibly have been damaged during installation. However, these hypotheses could not be proven. It was noted that all but one of the broken elements were in one cluster, and that this same cluster had historically had bridged and/or broken elements. Although the pulse valve for that cluster appeared to be functioning properly, it was replaced with a new valve. After these changes were made, the system operated for the rest of the quarter with no evidence of char breakthrough.

In early August, problems with the Dry Char Filtration System caused the plant to be taken off of coal operation. Subsequent inspection revealed that some of the filters were bridged and a number of broken filters were found in the vessels. The bridged and broken filters were located in the same two clusters of filter elements that were found to have problems during the previous two outages. These clusters had been replaced with clusters of new filters during a previous outage and when the system was returned to service the resulting disproportionate flow through these low-resistance clusters may have contributed to bridging and breakage. On another occasion, the clusters had been replaced with clusters containing a mixture of new and used filters, with the same resulting element bridging and breakage. In this case, the high-resistance filters in those clusters may have bridged because the pulse pressure generated was not sufficient to effectively clean them. The filters in both clusters were replaced with new filters, and a number of other high-resistance filters in the same vessel were also replaced to balance flow among the clusters and improve the capability for on-line pulse cleaning.

Prior to the August outage, two of the filter clusters had been configured with a bottom-fixing grid designed to restrict movement of the filters during pulse cleaning. In the event that a filter broke, the grid would keep the filter from separating and minimize char leakage through the break. The grid also prevented or minimized element breakage. During the outage, all the broken filters were found in one of the clusters containing a grid, but the other grid cluster did not have any broken (or bridged) filters. Therefore while it was surmised that the grid did not prevent breakage, it was also likely not the cause of the breakage. The grid appeared to hold the broken filters in place and minimize char leakage, but did not prevent pieces of the filter from falling off, leaving significant holes for char leakage. During the August outage, the grid was not re-installed on either cluster.

The internal gas distribution system in one of the dry char vessels was modified during the third quarter after computerized flow modeling revealed flow imbalances. The flow imbalance was subjecting some of the filter elements to high-velocity particle impingement. Inspections during previous outages had revealed areas of erosion on the filters, which damaged the surface membrane causing the filter to be ineffective. This loss of effective filtration resulted in higher velocities through the non-eroded filters in the vessels, which in turn made these more difficult to pulse clean. The modified system was designed to provide a more uniform distribution of flow in the vessel, and a corresponding reduction in particle velocity below the wear threshold. The Dry Char Filtration and Recycle System operated well during the approximately 340 hours of coal operation, which preceded the October/November extended plant outage. The system did not limit either plant availability or capacity.

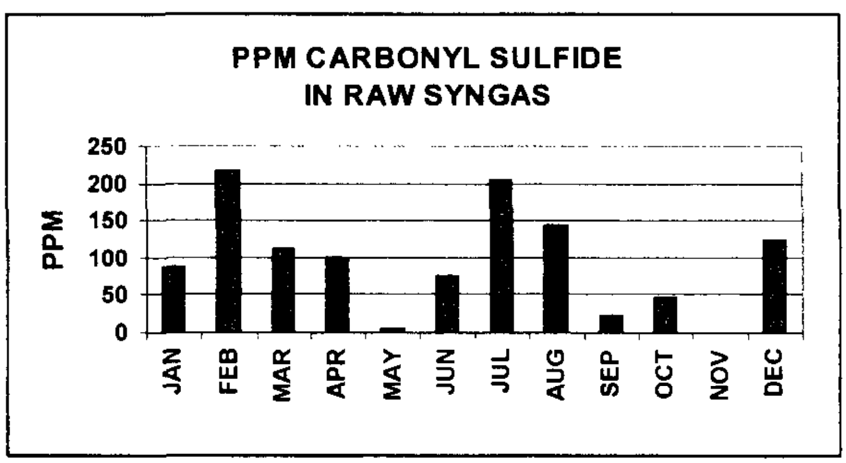
During the October/November extended outage, significant modifications were made to the char filtration system to resolve the ongoing problems experienced project to date. The primary improvement undertaken during the extended outage was the replacement of all the ceramic filter elements with metal elements. This single improvement reduced replaceable parts from over 22,000 in the ceramic assembly system, to less than 2,000 parts in the metal filter assembly system. The new system offers a more durable element, but introduces a higher concern for corrosion with the metallic elements. A second improvement was the installation of a heat exchanger designed to increase the temperature of the primary, and secondary, filtration system pulse gas above the dew point. The higher pulse gas temperature was designed to prevent condensation on the filters, thereby reducing the tendency for fouling and corresponding blinding and corrosion of the elements.

The following table summarizes operating campaigns, cause of down time and, corrective actions for forced outages due to the Dry Char Filtration and Recycle system:

CAMPAIGN	CAUSE	CORRECTIVE ACTIONS
FEB96B	Blow out of dry char recycle line to first stage reactor	Installation of "hardened" lining and/or alternate metallurgy recycle system piping and equipment
MAR96C	Gasifier trip due to high differential pressure on primary dry char filtration system	Came off coal operations for a short duration and back-pulsed primary filters while off line
MAR96D	Transferred off coal due to ineffective back-pulse pressure on primary dry char filtration system	Elective trip off of coal operations due to increasing differential pressures in the primary dry char filter system. Back-pulsed the system while off line and returned to coal operation
MAR96G	Transferred off coal due to ineffective back-pulse pressure on primary dry char filtration system	Elective trip off of coal operations due to increasing differential pressures in the primary dry char filter system. Back-pulsed the system while off line and returned to coal operation
MAR96J	Gasifier trip due to high differential pressure on primary dry char filtration system	Came off coal operations for a short duration and back- pulsed primary filters while off line
MAY96A	Transferred off coal due to high differential pressure on secondary dry char filtration system due to improper gaskets installed on filter element module tube-sheet	Preferred gaskets installed on primary filter element module tube-sheet prevents bypass of char to secondary system
JUN96A	Gasifier trip due to high differential pressure on secondary dry char filtration system due to primary filter element char loading and subsequent breakage	Effectiveness of back-pulse increased by increasing diameter of pulse gas nozzles.
AUG96A	Transferred off coal due to high differential pressure on secondary dry char filtration system due to uneven syngas flow leading to primary filter breakage	Internal gas distribution system is modified to assure even flow through filters. Metal filters replace ceramic filters in October/November outage.
DEC96F	Gasifier trip on high level in primary dry char filtration vessel	Dry char ejector was cleaned and put back into service

CARBONYL SULFIDE HYDROLYSIS CATALYST: Carbonyl Sulfide (COS) Hydrolysis Catalyst can have a direct impact on sweet syngas. Catalyst inefficiencies can result in high levels of COS within the product syngas. During runs early in the first quarter, COS removal efficiency in the catalyst beds began to decline. It was determined through sampling and analysis that the catalyst was being poisoned and blinded by arsenic and chlorides present in the syngas system. Catalyst degradation required the catalyst to be replaced during a February outage. Slipstream testing was initiated at this time to determine alternate catalyst selection. Catalyst efficiencies during the second quarter continued to decline indicating the need for an alternate catalyst or a means of eliminating the contaminating agents. Through the use of the slipstream unit, an alternate catalyst was selected which showed a greater resistance to poisoning. Additionally, an improvement project was identified which required the installation of upstream equipment to remove chlorides from the syngas stream. The effect of the project would be felt, not only in the COS hydrolysis system, but also in equipment down stream from the installation (this impact will be discussed in other parts of this report).

In the third quarter a new Chloride Scrubbing System (ClSS) was installed along with a new catalyst for COS hydrolysis. The new catalyst was not only lower in cost, but testing indicated that it would be more efficient and less vulnerable to arsenic and chloride poisoning. While initial start up and subsequent operation of this system went smoothly, a system start up in November led to an uncontrolled deflagration event in the system, which partially reduced the surface area of the catalyst and damaged the ClSS. The cause of this event was found to be the use of ambient air for pressure testing (rather than nitrogen) which created a spontaneous combustion event within the activated carbon filtering portion of the COS catalysis system. The damage in the ClSS system made it extremely difficult to isolate a final root cause of this event, but a step by step analysis dictates that this was the most probable cause. The investigation and repair of the system was completed and the plant returned to operation in December. Damage to the catalyst was not enough to warrant replacement. The result of electing not to replace the catalyst was an increase in the amount of COS in the product syngas for the month of December. Carbonyl sulfide levels between 50 to 100 ppm were normal during operation and somewhat higher (due to a lower syngas density) during startup operations. That notwithstanding, overall sulfur in the product gas was still well within environmental and contractual requirements in the product syngas. Overall efficiency of the COS catalyst will be carefully monitored and will be replaced when conversion efficiencies dictate. The chart at right depicts ppm levels of COS during 1996. Note that the months of April, May, August and September have skewed data due to shortened run hours during those months.



SYNGAS RECYCLE COMPRESSOR: The syngas recycle compressor recycles particulate-free raw syngas back to the dry char filtration system for use in filter back-pulse cleaning and, to the gasifier for use in the second stage reactor for syngas cooling. Recycled syngas is also used to atomize coal slurry in the second stage slurry burners and to prevent nozzle plugging in the methane preheat burners. Additionally, two cameras in the quench reactor and two in the second stage gasifier have a recycled syngas purge to prevent plugging of their sight paths. Syngas production was limited due to difficulties with the recycle syngas compressor in both January and March of 1996. At the end of January, a steady decline in the machine's second stage performance led to a complete overhaul. The source of the problem was severe ammonium chloride deposition due to condensate carryover into the compressor during methane operation. In lieu of re-opening the machine, the deposits were successfully removed in solution using a water-wash process. Because condensate carryover also occurs at a slower rate during coal operations, two improvement projects were instituted to minimize the long-term effects of this problem. A demister was installed during the fourth quarter in the suction knockout drum, which is designed to remove 99% of liquid carryover. A spray nozzle was also installed in the suction line to allow for an on-line water wash.

During the third quarter the compressor tripped on two separate occasions preventing the plant from going to coal operations. In early August, a discharge-end labyrinth seal failed. The cause of the failure was identified as chemical attack of the bronze seal material. The seal was replaced with a Teflon-based seal similar to the material of construction of the inter-stage seals, which had shown no signs of chemical attack. The shaft sleeve was also damaged when the seal failed, which required a rotor assembly replacement. Delays were encountered when mismatched parts were installed in the thrust bearing of the spare rotor, causing incorrect spacing of the impellers. The rotor was returned to the manufacturer for re-assembly before the compressor could be put back into service and tested. The new Teflon-based labyrinth seal failed shortly after the compressor was started up for a test run on nitrogen. An aluminum-based seal was then installed and, to date, has operated without failure. A trip off coal operation in late August was caused by the failure of one of the compressor impellers, which was found to have cracked and moved on the shaft. The cause of the crack was determined to be mechanical in nature, although it propagated due to chemical attack. The last time that this rotor assembly was in service was in early February of 1996, during which time a high discharge pressure excursion may have contributed to the eventual failure. The rotor assembly was replaced and the compressor operated for the rest of the quarter with no mechanical problems.

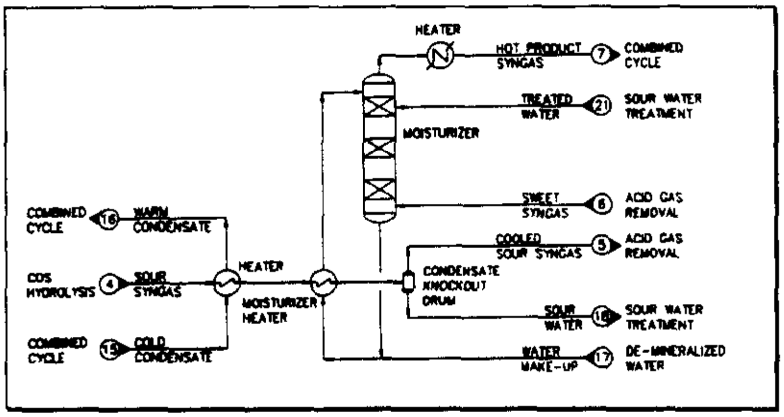
The recycle syngas compressor was disassembled, cleaned and re-assembled during the October/November outage. Although the compressor had not affected plant performance prior to the outage, operational data indicated that it was slightly fouled. A de-mister was installed in the suction knockout drum to limit moisture carryover to the machine. However, the first section of the compressor still operated as low as 90% of its expected performance during December. Since the second section of the machine operated at design during this time, it was concluded that volatiles in the syngas were likely condensing in the internal passageways of the first section, but were being carried through the second section because of the higher temperatures in that area of the compressor. However, the decline in first section performance was manageable and did not significantly affect plant performance.

PROJECT IMPLEMENTATION - Chloride Scrubbing System (ClSS): In the third quarter of 1996, the new Chloride Scrubbing System was installed. This capital improvement project is designed to remove chlorides and arsenic from the raw, particulate free syngas stream. The gas passes through a packed column to facilitate water contact and subsequent chloride and arsenic removal. Removal of the chlorides should substantially reduce problems associated with the chloride stress-corrosion cracking seen in downstream stainless steel equipment. Additionally, the raw syngas will be cooled by the system, which should enhance operation of the COS catalyst system. Removal of the arsenic component should also serve to extend COS catalyst bed life.

Some early problems were observed with the chloride scrubber system upon initial operation due to ammonia accumulation. Due to the scrubbing of hot syngas with sour water, the chloride scrubber was also functioning as an ammonia stripper. This resulted in ammonia water being recycled to the sour water tank, which in turn, was sent back to the ClSS. Within two days of operation, ammonia levels had exceeded 4% (40,000 ppm) in the scrubber water. This reduced efficiency and created some pluggage problems in the low temperature heat recovery unit due to the formation of carbonate and bicarbonate salt based scales. To abate further operational problems with the system, a blowdown was taken from the sour water tank directly into the sour water system to provide a purge of ammonia from the system. During the November shutdown, control of the blowdown was automated to provide consistent control of ammonia levels.

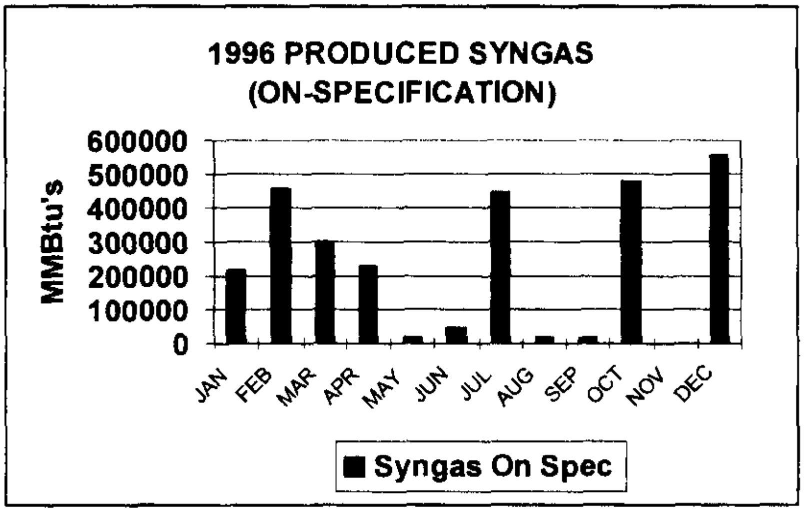
A deflagration event in the fourth quarter caused severe damage to the chloride scrubber system, especially to the internals of the scrubbing column and knockout drum. Cause and effect of this event has been previously discussed under the Carbonyl Sulfide Catalyst system and will not be reproduced here. Once the system was repaired and returned to service, the unit operated within design parameters for the remainder of the year.

LOW TEMPERATURE HEAT RECOVER AND SYNGAS MOISTURIZATION



After exiting the COS hydrolysis unit, the remaining low level heat is removed from the syngas in a series of shell-and-tube exchangers located before the Acid Gas Recovery (AGR) system. This cooling condenses water, ammonia, carbon dioxide, and some hydrogen sulfide (H_2S), which produces sour water. The sour water is collected in a condensate knockout drum and sent to the sour water treatment unit. The heat removed prior to the AGR system provides moisturizing heat for the product syngas, steam for the AGR H_2S stripper, and condensate heat.

Cooling water provides trim cooling to ensure the syngas enters the AGR near its design temperature (approximately 100 degrees F). The cooled sour syngas is fed to an absorber in the AGR system where the solvent selectively removes H_2S to produce a sweet syngas low in total reduced sulfur. The sweet syngas is then moisturized to a water content of approximately 22% by volume using low level heat from raw syngas cooling. Moisturization is accomplished by contacting the sweet syngas and hot water counter-currently in a high surface area contacting column. After the moisturizer, the syngas is preheated before being directed to the combustion turbine. Moisturization and preheating of the syngas increases efficiency in the combustion turbine and reduces the steam requirement for NO_x control.



Sweet syngas (product syngas) production for 1996 totaled 2,769,683 MMBtu's with the highest production occurring in the fourth quarter. Sweet syngas moisturization operated efficiently and provided a consistent product gas moisture content of approximately 20%-23% throughout 1996. Product syngas quality remained high and will be discussed later in this section.

While operations within the Low Temperature Heat Recovery area were within design parameters, three of the exchangers suffered tube failures due to chloride stress-corrosion cracking of the stainless steel tubes. Two of these exchangers serve to transfer heat between sour syngas and water from the Sweet Syngas Saturator system. Since the sour syngas side operates at higher pressure, an exchanger leak results in product syngas being contaminated with the sour syngas. A third exchanger cross-exchanges sour syngas with amine from the Acid Gas Removal (AGR) system. A tube leak into this system causes overpressure of the AGR as well as other operational problems within that area. Those exchangers operating at lower temperatures within this system have shown no signs, to date, of any chloride stress-corrosion cracking.

The plant had to be taken off of coal operation in early April due to excessive tube leaks from the syngas/amine exchanger. Leaking tubes were plugged in this exchanger as well as additional tubes in one of the sour syngas/water exchangers. Replacement exchangers for the syngas/amine exchanger and one of the syngas/water exchangers arrived on site in late April and were installed during the June outage. The replacements were constructed of an upgraded material and will not be vulnerable to chloride stress-corrosion cracking. Tests were performed on tubes within the remaining syngas/water exchanger during the outage. Based on results of these tests, an additional 10% of the tubes in this exchanger were deemed suspect to cracking and were plugged as a proactive measure to prevent future tube failures.

PRODUCT SYNGAS QUALITY: Product syngas quality remained relatively consistent throughout 1996. One of the primary reasons for this was the use of a single coal source for the year. Minor variations in hydrogen sulfide and carbonyl sulfide concentrations (in ppm) were primarily due to equipment problems in the COS catalyst reactor and acid gas recovery systems. Variations in hydrogen content, carbon dioxide and carbon monoxide concentrations, and methane content were directly related to operational characteristics of the system (and more specifically to variations in the oxygen to coal ratios of the gasifier feed) and cannot be attributed to variations in coal feedstock.

Hydrogen Content: Hydrogen content (weight-percent) in the syngas varied from an average monthly low of 32.87% in December to a high of 34.21% in June. Average concentration for Hydrogen in the product syngas for 1996 was 33.68%

Carbon Dioxide Concentration: Carbon dioxide (weight-percent) in the syngas varied from an average monthly low of 14.89% in July to a high of 17.13% in May. Average concentration for Carbon Dioxide in the product syngas for 1996 was 15.86%.

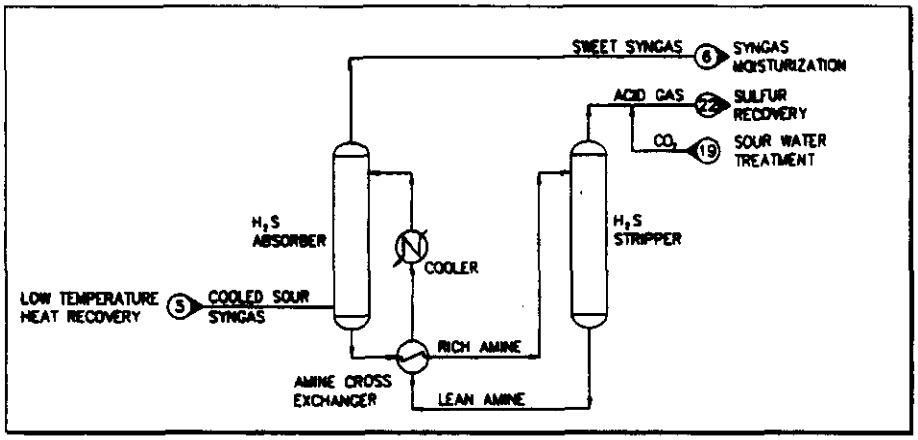
Carbon Monoxide Concentration: Carbon monoxide (weight-percent) in the syngas varied from an average monthly low of 42.34% in May to a high of 46.03% in October. Average concentration for Carbon Monoxide in the product syngas for 1996 was 44.44%.

Methane Content: Methane (weight-percent) in the syngas showed very little variability throughout the year. A low value of 1.26% was recorded in January with a high of 1.99% being recorded in December. Average concentration for Methane in the product syngas for 1996 was 1.82%.

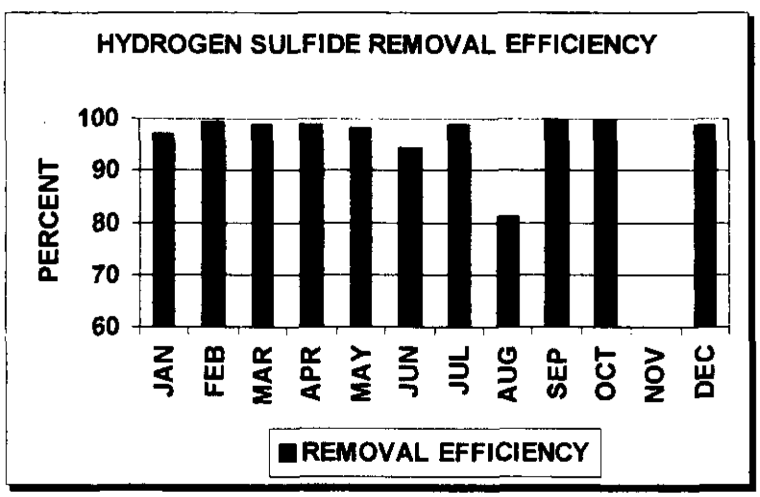
Hydrogen Sulfide Concentration: H2S concentration (parts per million or ppm) in the product syngas showed some variability due to acid gas recovery system equipment problems. A high value of 83.36 ppm was recorded in March while a low value of 17.28 ppm was recorded in June. The June value is somewhat suspect due to the reduced number of operational hours for that month. Average concentrations of Hydrogen Sulfide for 1996 were 39.39 ppm (this value is presumed to be statistically low due to the June value and a high standard deviation between monthly averages).

Carbonyl Sulfide Concentration: COS concentration (ppm) in the product syngas shows an expected variability due to the equipment problems discussed previously in this report. The highest average monthly values are normally those that occurred in the months immediately prior to or during the months of catalyst change-outs. February of 1996 had the highest average monthly value for Carbonyl Sulfide at 162.13 ppm. A low value of 36.26 ppm was recorded for a monthly average in May. A 1996 monthly average of 64.89 ppm is probably higher than anticipated future values due to the fact that there was substantial deviation in the average monthly values due to the problems with the catalyst system. Additionally, the system only operated one month (December) with a fully functioning chloride scrubbing system and, even then, the COS catalyst was partially deactivated due to the deflagration event.

ACID GAS REMOVAL



The first step in the sulfur removal and recovery process is the Acid Gas Removal (AGR) system, which removes the hydrogen sulfide (H_2S) present in the sour syngas. The AGR system also produces a concentrated H_2S stream (acid gas) that is fed to the Sulfur Recovery Unit (SRU). The AGR system is a totally contained system and does not produce emissions to the atmosphere. H_2S is removed in the absorber using an H_2S solvent, methyl diethanol amine (MDEA). The H_2S rich solvent exits the absorber and flows to a reboiled stripper where the hydrogen sulfide is steam stripped at low pressure. The concentrated H_2S stream exits the top of the stripper and flows to the sulfur recovery unit. The lean amine exits the bottom of the stripper and is cooled, then recycled to the absorber.



Hydrogen sulfide removal efficiencies remained fairly consistent throughout 1996 as can be seen by the chart at right. The efficiency calculation uses total combustion turbine stack and flare stack syngas emissions (as sulfur) compared to the total sulfur feed to the gasification plant (sulfur, dry-weight percent) for the most conservative estimate of performance. Acid gas removal efficiency dropped in August due to problems with the amines reclamation unit, which keeps the amines solvent low in heat stable salts. High salts concentration in the amine causes lower absorption efficiencies. AGR system performance was up in the final quarter of the year due to cooler ambient temperatures, which allows cooler amines temperatures, and despite continued high solvent heat stable salts loading. November had no unit operating days and contributed nothing to quarterly performance. Good overall efficiency for the quarter was due to extended operational periods during October and December, which allowed for system optimization.

The following small scale project improvements were completed within the AGR area in 1996:

- Design oversights for the internals of the acid gas solvent regenerator were identified in the first quarter. As a result of the deficiency, operation and maintenance costs increased due to solvent attrition, higher startup quench water requirements, increased ammonia break-through to the sulfur recovery unit, reduced solvent strength and a slight efficiency penalty due to reduced solvent inventory. Modifications incorporated to the system in May (redesign of the internals) appear to have rectified the problem. Reductions in operation and maintenance costs have been realized along with reduced startup quench water demand and a reduction in the ammonia concentration and break-through to the sulfur recovery unit.

- The amine solvent feed pumps to the absorber column received modifications during the second quarter in the form of automatic re-circulation valves incorporated at each pump discharge. These valves ensure that each pump has minimum safe flow during all periods of operation through the normal discharge pipe and/or through a common return line to the surge tank. This process replaced an orifice and automatic block valve return system, which had incurred high maintenance costs due to flashing flow and subsequent eroded piping.

- In the third quarter a pressure drop reduction project was installed for the lean amine return piping. This pressure reduction allows for increased circulation rate to counter the efficiency reductions in summer months due to increased ambient temperatures. The project focused on increasing the line size at a point where the stripper bottoms level control valve had been removed in 1995 leaving only the reduced area bypass loop for flow. The project reduced the system head pressure by 36 psig and allows for about 200 gpm increased amine flow.

- During the fourth quarter a three-way sway brace dampening system was installed for the absorber column level control valve. This valve endures extreme pressure drop and flashing two-phase flow as the solvent enters the low-pressure amine stripping column. High cycle vibration fatigue was a concern and the dampening system eliminates potential consequences of failure.

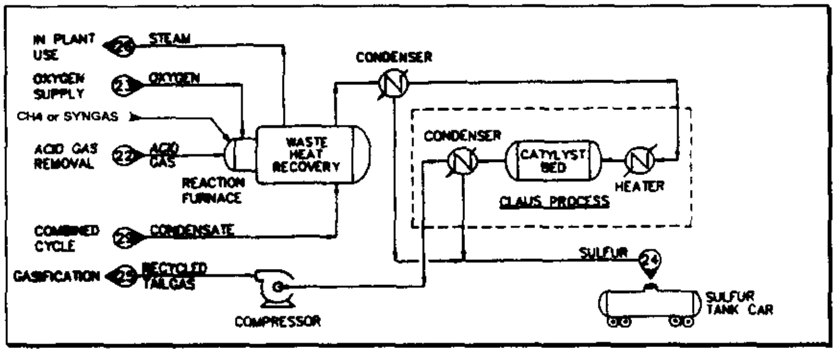
- To optimize filter life for the regenerator quench slipstream filters, new pressure point taps were installed allowing for differential pressure data acquisition across each of the four vessels.

- The Ion Separation (ISEP) unit, designed to remove heat stable salts from the MDEA, experienced operational problems throughout the year. Early in 1996, efforts were undertaken to increase salt removal capacity through regenerant feed system modifications. By the second quarter, heat stable salts loading on the MDEA increased to the point where it was necessary to call in an outside vendor to remove the salts via a portable vacuum distillation process. This process reduced the salts to a satisfactory level and restored the amine absorption capability to an acceptable level. Feed system modifications completed late in the second quarter were designed to boost capacity and utilize down time for solvent reclaim process operation. Multiple cell failures in the third quarter also created excessive down time and are being investigated to determine suitability of the cell material. Project installation included a condensate cooler to prevent thermal shock to the resin resulting from elevated chemical feed dilution temperatures.

- During the third quarter, a project was implemented to install chemical feed pulsation dampeners in the ISEP system to improve feed consistency and reduce chemical attack of the resin

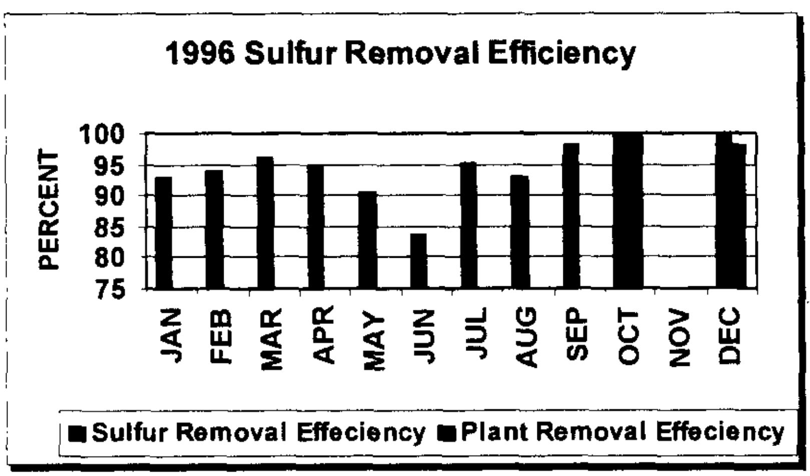
- The cells containing resin began experiencing failures in the third quarter of 1996. An investigation was launched to determine if a reaction is occurring which consumes the cell material. Results of the investigation were inconclusive and the unit continued to suffer leaks in the pressure containing cell walls. A development effort is underway to identify an appropriate long-term cell lining material. This effort is being administered jointly between the ISEP equipment manufacturer and Destec. The process modifications made within the ISEP system in 1996 have increased heat stable salt removal efficiency, but it is still short of the required removal rates needed at full load operation. Destec is investigating the use of a replacement resin and/or the potential of increasing the size of the resin cell, to increase performance in 1997.

SULFUR RECOVERY



The concentrated H_2S stream from the AGR system and the CO_2 and H_2S stripped from the sour process water are fed to a series of catalytic reaction stages where the H_2S is converted to elemental sulfur. The sulfur is recovered as a molten liquid and sold as a by-product. A tailgas stream, composed of mostly CO_2 and N_2 with trace amounts of H_2S, exits the last catalytic stage.

The tail gas from the Sulfur Recovery Unit (SRU) is hydrogenated to convert all the sulfur species to H_2S, cooled, compressed and then directed to the gasifier. This allows for a very high sulfur removal efficiency with minimal recycle requirements. Provisions in the system will allow for final treatment of the tail gas in the tail gas incinerator. A tank vent stream is also treated in the incinerator. The tank vent stream is composed of air purged through various in-process storage tanks and contains very small amounts of acid gases. The high temperature incinerator efficiently destroys the H_2S remaining in the stream by converting it to SO_2 before the exhaust gas is vented to the atmosphere from a permitted air emissions source.



Sulfur recovery efficiencies indicated at left are split into two specific areas. The blue columns indicate the efficiency of the SRU by comparing total stack emissions with total sulfur feed to the SRU. Overall Plant removal efficiencies (green columns) compare total joint venture emissions (as sulfur) verses total sulfur feed to the gasifier. Overall, this graph compares favorably with the reduction in reactivity of the COS catalyst and is representative of degradation and replacement over the course of 1996. Fourth quarter, following the installation of the chloride scrubbing system and improvements in the AGR system, shows a significant increase in the removal efficiency of the SRU. A total of 3,289 tons of sulfur were recovered during 1996.

Increased sulfur production and recovery efficiency figures are related to improvements in the tail gas handling systems. The improvements include:

- Installation of an acid gas bypass line to the hydrogenation reactor and recycle compressor strainer modifications. The acid gas bypass line increased hydrogenation catalyst activity via a re-sulfiding process which reduced sulfur formation and pluggage throughout the tail gas handling system. Filter modifications allow discretionary filtering, permitting small particle passage while retaining machine protection to reduce the rate of strainer pluggage and compressor down time. As the tail gas recycle rate increased, sulfur plant recovery efficiency and production increased.

- A project to enhance sulfur area safety and storage tank capacity was implemented in the second quarter. The project consisted of a new vent line to the incinerator allowing the tank to operate at lower pressure. The sulfur storage tank usable capacity was increased from 40% to 100% in the second quarter with implementation of a new steam jacketed vent line to the tank vent incinerator. The new line isolates the tank from SRU process pressures, resulting in maximum safe capacity and eased sulfur loading restrictions.

- In September, a new project was implemented allowing acid gas feed to the SRU prior to coal feed to the gasifier. This increases total recovery by allowing high recovery during startups and results in the increase in efficiency for the last month in the third quarter. In October, new process-control implementation allowed acid gas feed to the SRU after coal operations cease, thereby reducing emissions at the acid gas flare. The result is increased total recovery and increased efficiency for the fourth quarter of 1996.

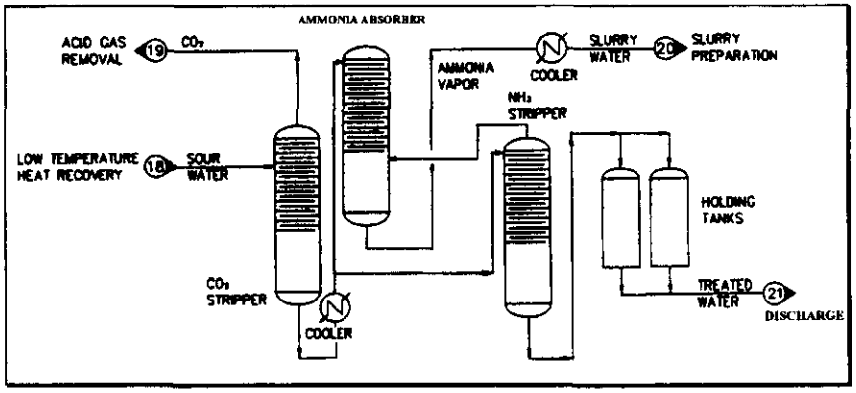
- Some projects were implemented for the SRU in the fourth quarter designed to enhance safety and reduce O&M costs. A rail car level transmitter replaced the originally installed detection systems, which allows more consistent sulfur rail car loading and reduced potential for overfilling. Several lines in the SRU were modified to include double block and bleed (DBB) isolation in strategic locations. This eliminates significant line blinding and safe tagging efforts for vessel entry and allows SRU steam and condensate outages without forcing plant wide outages. Finally, the SRU area steam trap system was re-thought and reconfigured to eliminate ice hazards as well as a net reduction of 28 obsolete traps.

- SRU support systems also received project improvements. The intermediate pressure steam boiler required installation of upgraded tie rods to minimize tube vibration. The tank vent compressor knockout drum level monitoring system was redesigned for earlier high level warning. One of the two lower explosive limit (LEL) metering systems within the tank vent system was relocated to a position where positive blower pressures would not affect accuracy, reducing nuisance alarming and excessive re-calibration. These improvements will positively impact operability and reduce maintenance needs.

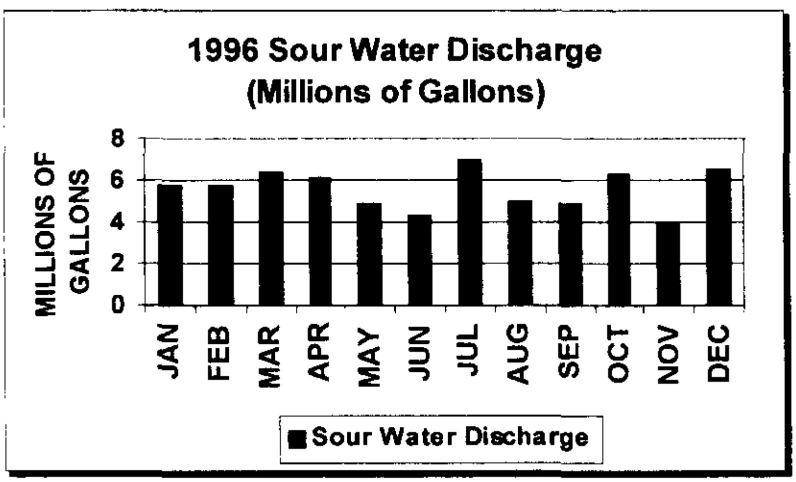
Several significant events occurred during the year regarding the Tail Gas Incinerator air permit. First of all, stack testing for both Sulfuric Acid Mist and Carbon Monoxide was completed during the first quarter. Both parameters tested in compliance at 0.042 lbs/hr of Carbon Monoxide and 2.6976 lbs/hr of Sulfuric Acid Mist. Carbon Monoxide permitted compliance limits for the incinerator stack are 11,099 lbs/hr while Sulfuric Acid Mist limits are set at 3.79 lbs/hr. In the second quarter, stack testing was completed as required for verification of the SO_2 concentration and flow monitor. The SO_2 and flow monitor is subject to the requirements of 40 CFR Part 75, Appendix A and B; and 40 CFR Part 60, Appendix A and B, Performance Specifications 2 and 6.

The relative accuracy test (RATA) is performed to assess the accuracy and to validate the calibration technique of the continuous emission monitors. Relative accuracy represents a comparison of pollutant and diluent concentrations determined by the continuous emission monitors to pollutant concentrations concurrently measured using EPA reference methods. EPA Instrumentation Reference Method 6C (SO2) described in 40 CFR Part 60, Appendix A, was followed for this determination. Relative accuracy tests were conducted on April 24th in accordance with the protocols delineated in the above referenced regulations.

A total of eleven 30-minute reference method test runs were conducted during one calendar day for the SO_2 analyzer. The relative accuracy test was conducted simultaneously with the stack SO_2 monitor and the measured pollutant concentrations were calculated to a lbs/hr basis before performing the Relative Accuracy calculations using measured stack volumetric flow rates for each run. Sulfur Dioxide testing revealed an average SO_2 output, at maximum load on the combustion turbine, of 342.7 lbs/hr (average) and a relative accuracy of 6.89%. The flow meter proved relative accuracy of 3.25%. Both meters passed the relative accuracy requirements of the regulations and demonstrated permit compliance for SO_2 emissions by operating at maximum capacity and being below the permit limit of 527 lbs/hr.



Water condensed during cooling of the "sour" syngas contains small amounts of dissolved gases, i.e. carbon dioxide (CO_2), ammonia (NH_3), hydrogen sulfide (H_2S), and trace contaminants. The gases are stripped out of the sour water in a two step process. First the CO_2 and the bulk of the H_2S is removed in the CO_2 stripper column by steam stripping. The stripped CO_2 and H_2S are directed to the SRU. The water exits the bottom of the column, is cooled, and a major portion is recycled to slurry preparation. Any excess water is treated in the ammonia stripper column to remove the ammonia and remaining trace components. The stripped ammonia is combined with the recycled slurry water. The treated water can be directed to the moisturizer or discharged from the plant. If out of specification for discharge, the treated water can be stored in holding tanks for further testing or recycle to the sour water system. Discharge of this water stream is controlled or regulated as a combined stream with PSI's plant discharge into water outfall pond 102.

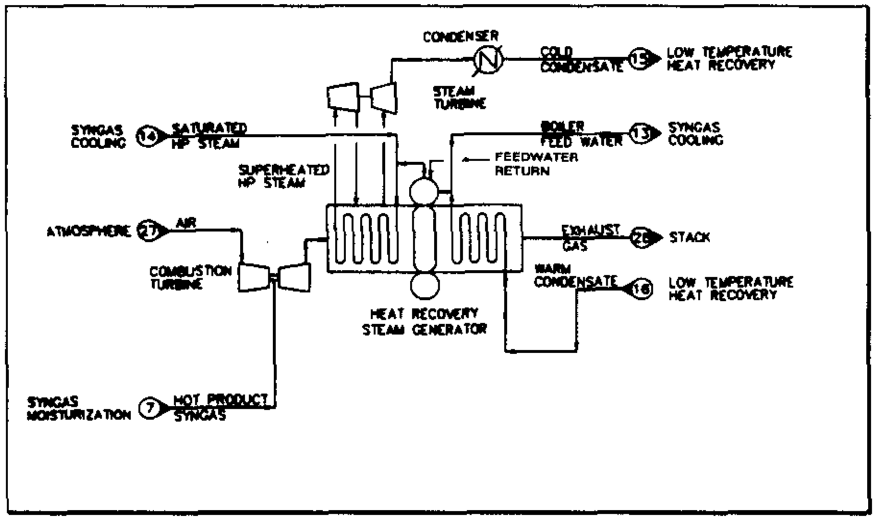


As depicted at left, sour water to the outfall varied from a high in July of 7 million gallons to a low in November (a non-production month) of 3.9 million gallons in 1996. In the second quarter, operational philosophies for the sour condensate treater were changed to allow increased chloride purge from the system and less recycle to slurry production plant areas. No problems, or operating difficulties were encountered as a result of these changes.

In the third quarter of 1996, operating data revealed the acid degassing and ammonia stripping columns were exhibiting signs of tray damage. Inspections confirmed the data and revealed significant damage, which was likely due to liquid flooding of the columns. In addition, damage patterns suggested flashing liquid feed flow to the stripping column was responsible for the loss of about 20% of the column trays. A new liquid feed distributor was installed to control hammering of the trays. Operating parameters were revised with the inclusion of 3 modified, and 4 new, control system alarms to warn of impending liquid flood.

Specific information about the quality of the water to the outfall is covered under the 1996 Environmental Monitoring Plan Annual Report and can be used as an additional reference to provide more specific information about discharge quality.

COMBINED CYCLE POWER GENERATION



The combined cycle system consists of a combustion turbine generator, heat recovery steam generator (HRSG), reheat steam turbine generator, condenser, deaerator, flash drums, condensate pumps and boiler feedwater pumps.

The gas turbine (GT) is a nominal 192 MW advanced cycle combustion turbine fueled primarily by syngas. Fuel moisturization and steam injection controls NOx emissions and increases MW output. Combustion air is drawn through inlet filters from outside the building housing the gas turbine. Combustion exhaust gases are routed to the HRSG. No. 2 fuel oil is used as back-up fuel for the gas turbine during startup and shutdown, and for other periods when syngas is unavailable. Fuel oil is stored in tanks located within the existing plant.

The HRSG recovers heat from the GT exhaust gases to generate high pressure steam. This steam, combined with steam from the syngas HTHRU, re-powers the Unit 1 reconfigured steam turbine. Steam generated in the HRSG is piped to and from the steam turbine through extensive piping additions. The HRSG receives GT exhaust gases and generates steam at 1600 degrees F and 1000 degrees F (main steam) and re-heats extraction steam from the steam turbine back to 1000 degrees F at about 750 psig extraction pressure (reheat steam). The HRSG is specifically designed for high operating efficiency and configured for horizontal flow through a series of vertical heat transfer modules. Design of the HRSG is optimized for a syngas-fired gas turbine.

The Wabash River Station Unit 1 steam turbine is located in the existing powerhouse. The steam turbine was originally supplied by Westinghouse and went into commercial operation in 1953 at a nominal rating of 99 MW.

The turbine was designed for reheat operation with five levels of extraction steam used for feedwater heating. In the repowered configuration, the gasification facility and the HRSG are capable of providing main steam and reheat steam. To maximize efficiency, feedwater is heated in both the HRSG and the gasification plant. With the need for extraction steam from the steam turbine eliminated, the steam previously extracted passes through the steam turbine to generate 105 MW of power. As a result, minor modifications to the turbine steam path ensure acceptable steam path velocities. The generator and main power transformer continue to be used and have required only minimal modification.

The following table illustrates production during 1996:

	1 QTR	2QTR	3QTR	4QTR	TOTAL
Combined Cycle Operating Hours On Syngas	**535**	**148**	**289**	**580**	**1,552**
Longest Continuous Run Hours On Syngas	**127**	**115**	**152**	**130**	
Maximum CT Output (MW)	**192**	**189**	**186**	**180**	
Maximum ST Output (MW)	**96**	**89**	**92**	**90**	
Total Gross Generation (MWHours)	**163,088**	**45,332**	**80,230**	**95,710**	**384,360**

During 1996, no capital improvement projects or major equipment modifications were undertaken by PSI. Equipment operated as designed and the only key area of change was the identification of proper operating parameters for the combustion turbine and steam turbine this first commercial year. No specific problem areas were identified in 1996.

In 1996, the water treatment systems processed over 420.8 million gallons of Wabash River water for use in the gasification and re-powering areas of the facility. Of this total, approximately 110.6 million gallons were demineralized for use within the High Temperature Heat Recovery Unit of the gasification process and the Heat Recovery Steam Generator at the exhaust of the combustion turbine. All other demands for water were met by the water treatment facility.

Budget Period 3 Activities

Budget Period 3 began on November 18, 1995. Maintenance costs incurred in 1996 were higher and availability lower than expected due to the problems discussed above. The costs shown also reflect major process improvements implemented in 1996. However, operations and systems data collected in the first year of operations will assist in the demonstration and commercialization of the technology.

	Revised Baseline Budget (per Cont. App. for Budget Period 3)	**Actual Budget Period 3 Spending as of 12/31/96**
Participant Share	$52,300,566	$31,193,315
DOE Share	$52,300,566	$20,863,186
Total	$104,601,132	$52,056,501

DOE Reporting and Deliverables

Spending and budget reports were submitted on both a monthly and quarterly basis according to the requirements of the Cooperative Agreement. Project reviews and Joint Venture quarterly reports were provided to the DOE. The following reporting requirements were submitted in accordance with Attachment C, sections 6 and 7 of the Cooperative Agreement:

- Project Management Plan
- Environmental Monitoring Reports
- Operations Summary Reports

Other Activities

Several public relations and education activities were carried out in 1996. Appendix C (Tab C) provides a list of selected public information and trade and technical papers presented by Destec or PSI personnel related to the WRCGRP.

1997 ACTIVITIES AND MILESTONES

Activities in 1997 will focus primarily on continued evaluation of new project installations and renewed focus on proper gasifier operations. Major activities for 1997 will include the following:

- Evaluate the Dry Char system element metallurgy.
- Evaluate gasifier temperature control to aid in prevention of ash deposition.
- Achieve an increasingly effective understanding of the systems and subsystem operating characteristics.
- Maintain/improve the expected dispatch orders in the Cinergy system.
- Fulfill the provisions of the Environmental Monitoring Plan.
- Obtain the data base and experience-base necessary to advance and meet the commercial markets for the technology.

Other Activities

Other activities of significance include meeting the DOE review and reporting requirements and further development of effective operations and maintenance programs. During 1997 community relations and education programs will be continued.

APPENDIX A

Glossary of Acronyms

Appendix A
Glossary of Acronyms

CAAA	-	Clean Air Act Admendments
CCT	-	Clean Coal Technology
CGCC	-	Coal Gasification Combined Cycle
COS	-	Carbonyl Sulfide
DOE	-	Department of Energy
EPA	-	Environmental Protection Agency
HHV	-	Higher Heating Value
HRSG	-	Heat Recovery Steam Generator
IDEM	-	Indiana Department of Environmental Management
ISEP	-	Ion Separation unit
LGTI	-	Louisiana Gasification Technology, Inc.
NEPA	-	National Environmental Policy Act
NPDES	-	National Pollutant Discharge Elimination System
P&ID	-	Piping and Instrument Drawings
PMP	-	Project Management Plan
PON	-	Program Opportunity Notice
WRCGRP	-	Wabash River Coal Gasification Repowering Project

APPENDIX B

List of Figures

Appendix B
List of Figures

Figure 1	General Site Map
Figure 2	Site Map on Wabash River
Figure 3	Project Plot Plan
Figure 4	Photograph
Figure 5	Process Schematic
Figure 5A	Figure 5 - Continued
Figure 6	Block Flow Diagram
Figure 7	Photograph
Figure 8	Project Organization
Figure 9	Project Milestones
Figure 10	Project Plan
Figure 11	Plant Operation Statistics

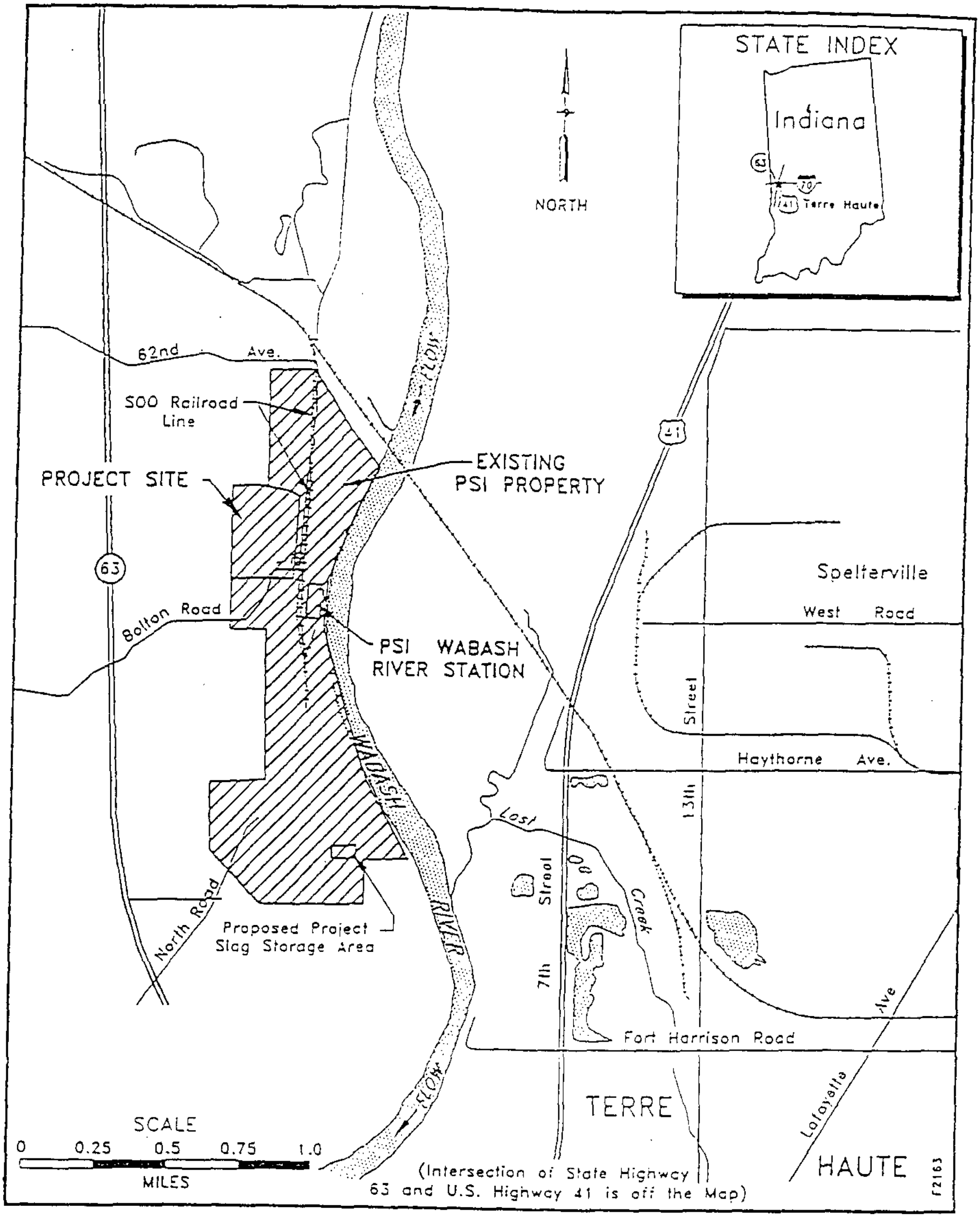


Figure 1 General Location Map Showing the Site of the Project

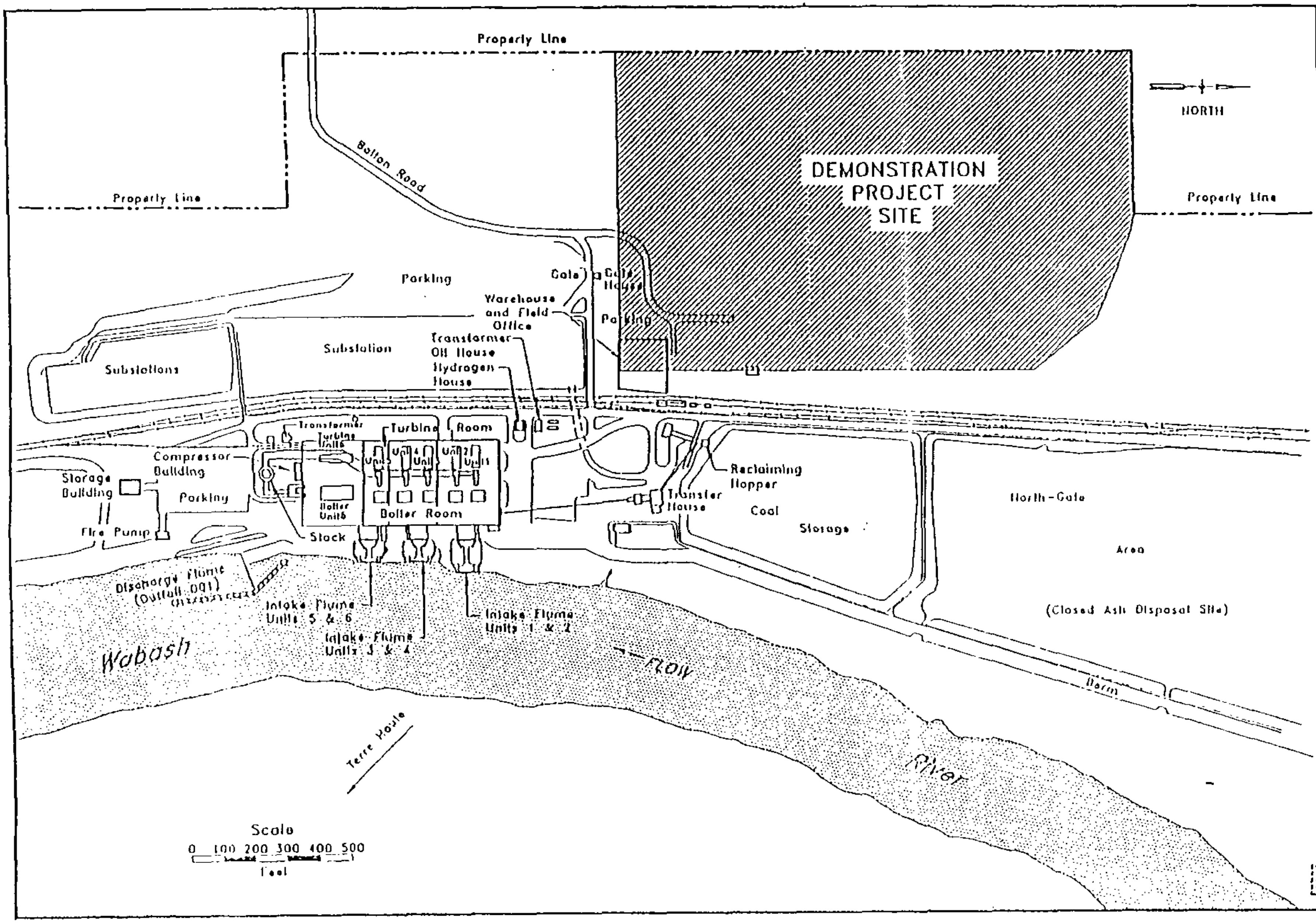


Figure 2 Site Map of the Wabash River Generating Station

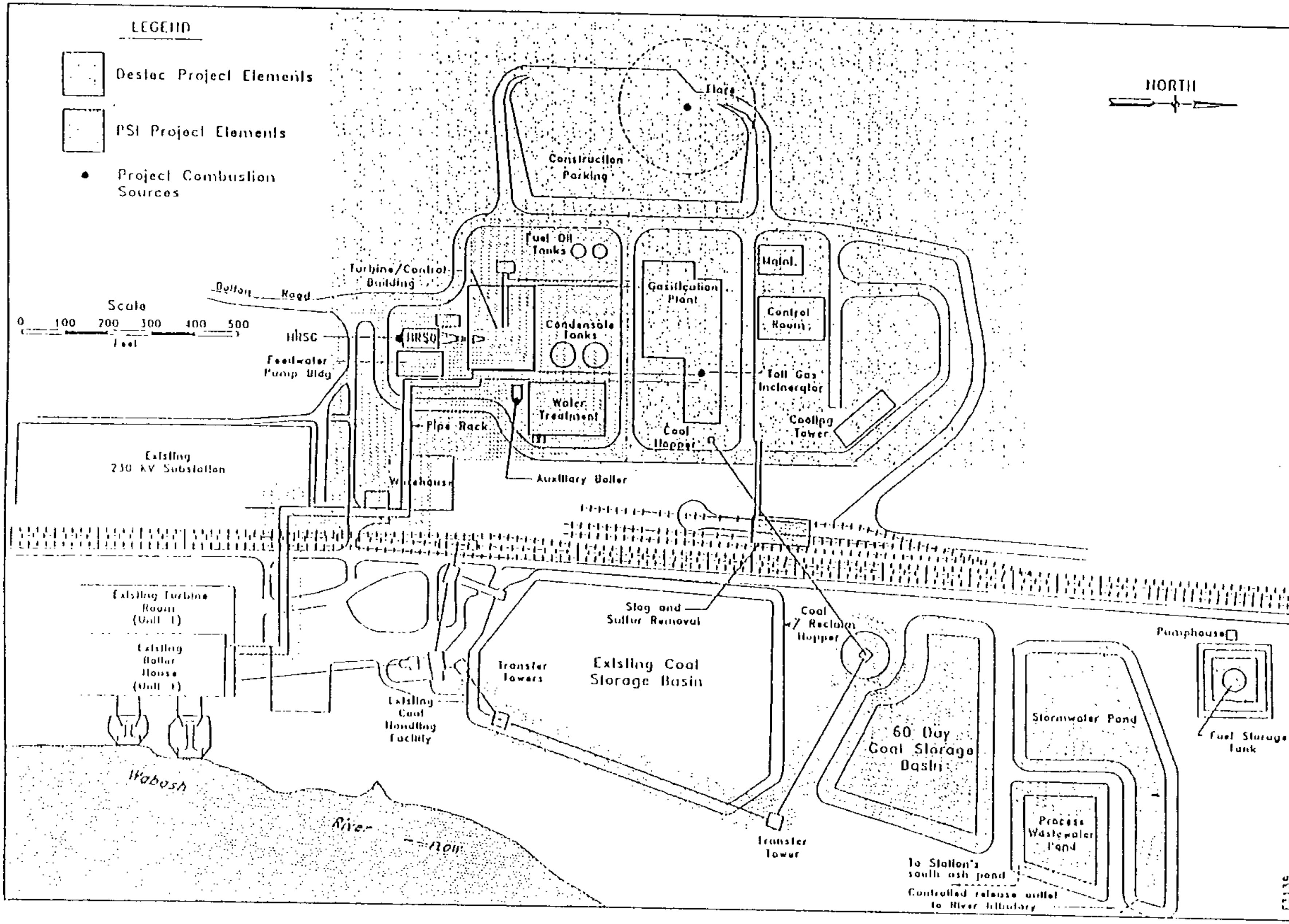


Figure 3 Project Plot Plan

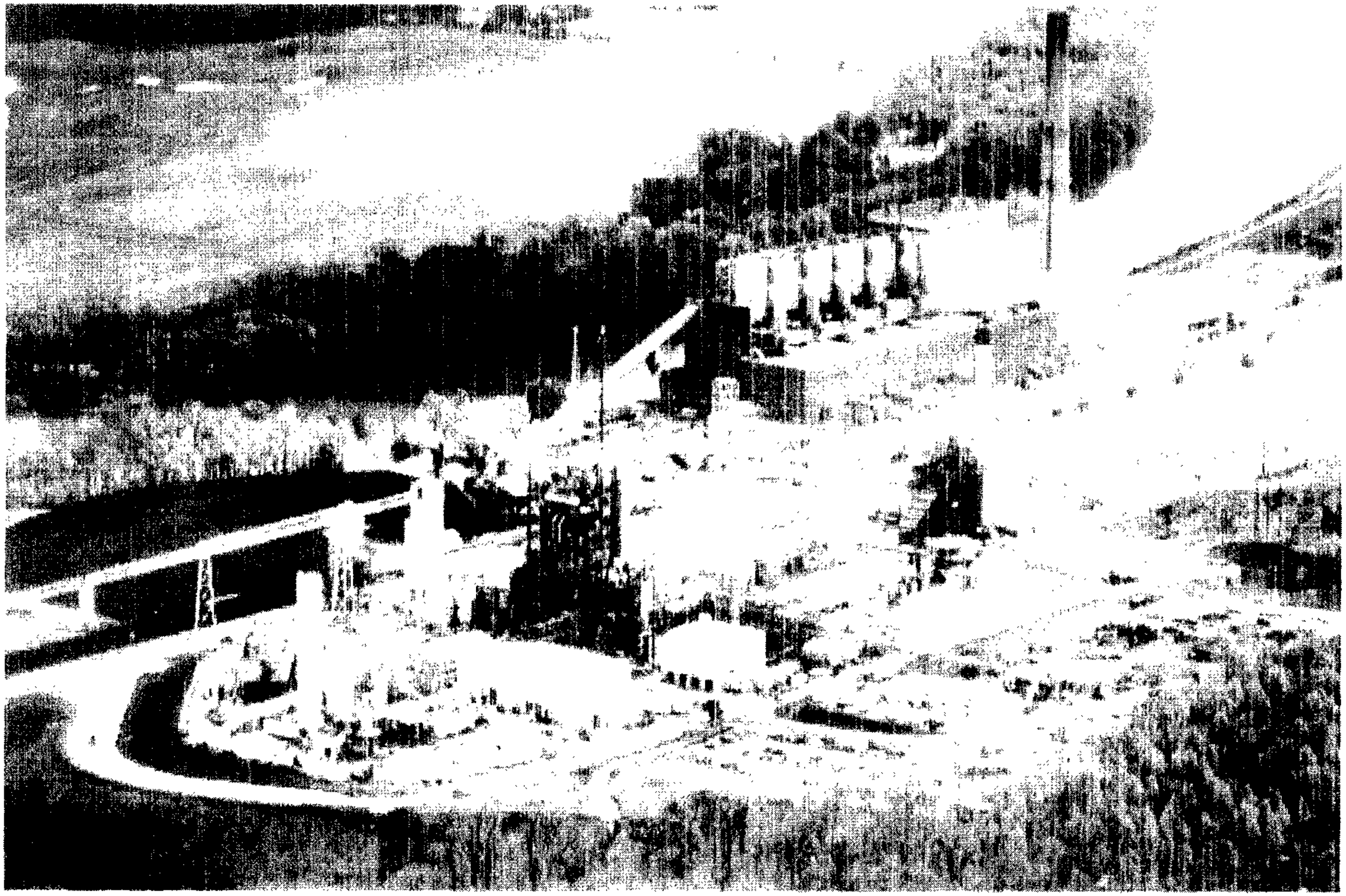


Figure 4

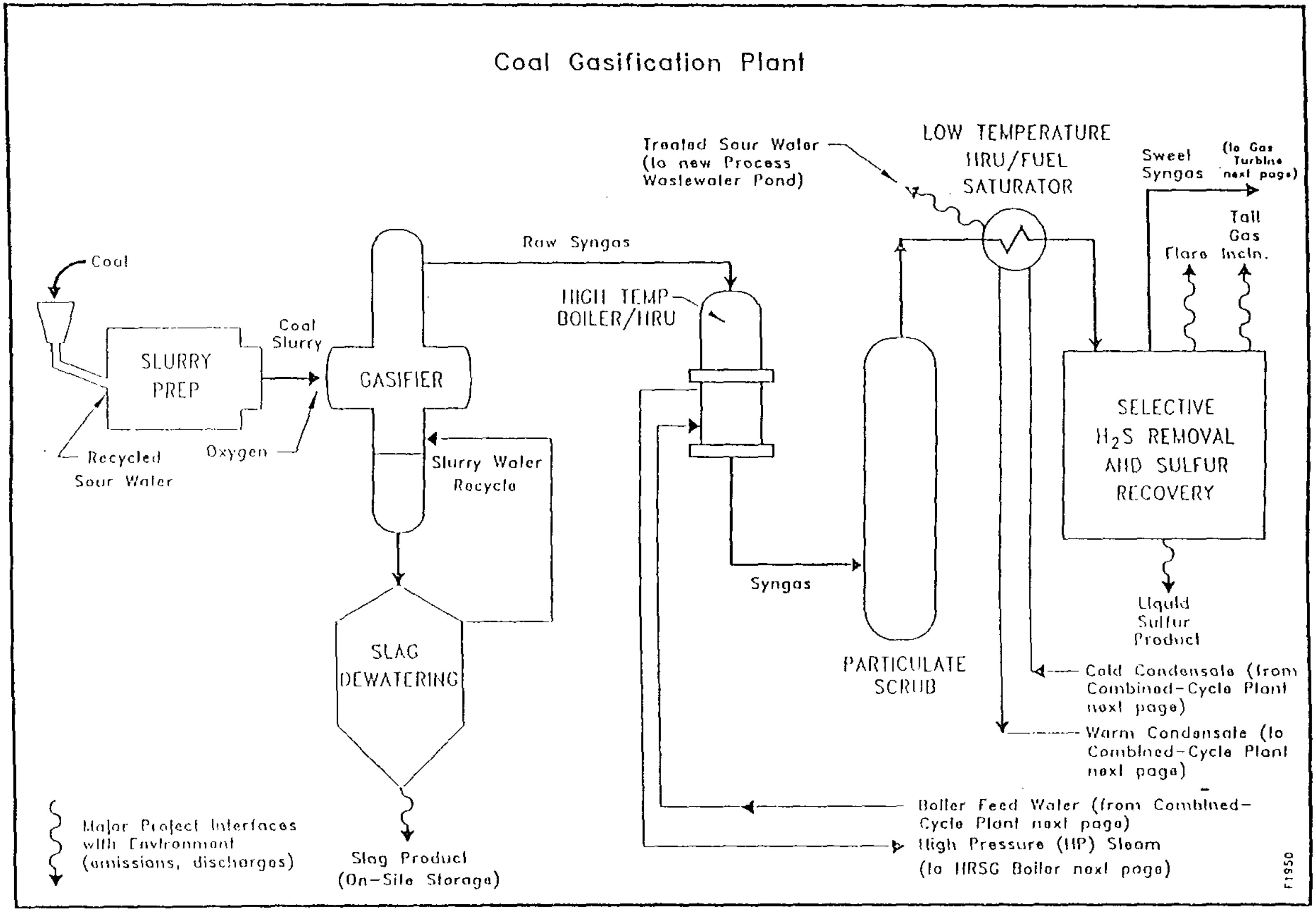


Figure 5 Conceptual CGCC Process Schematic

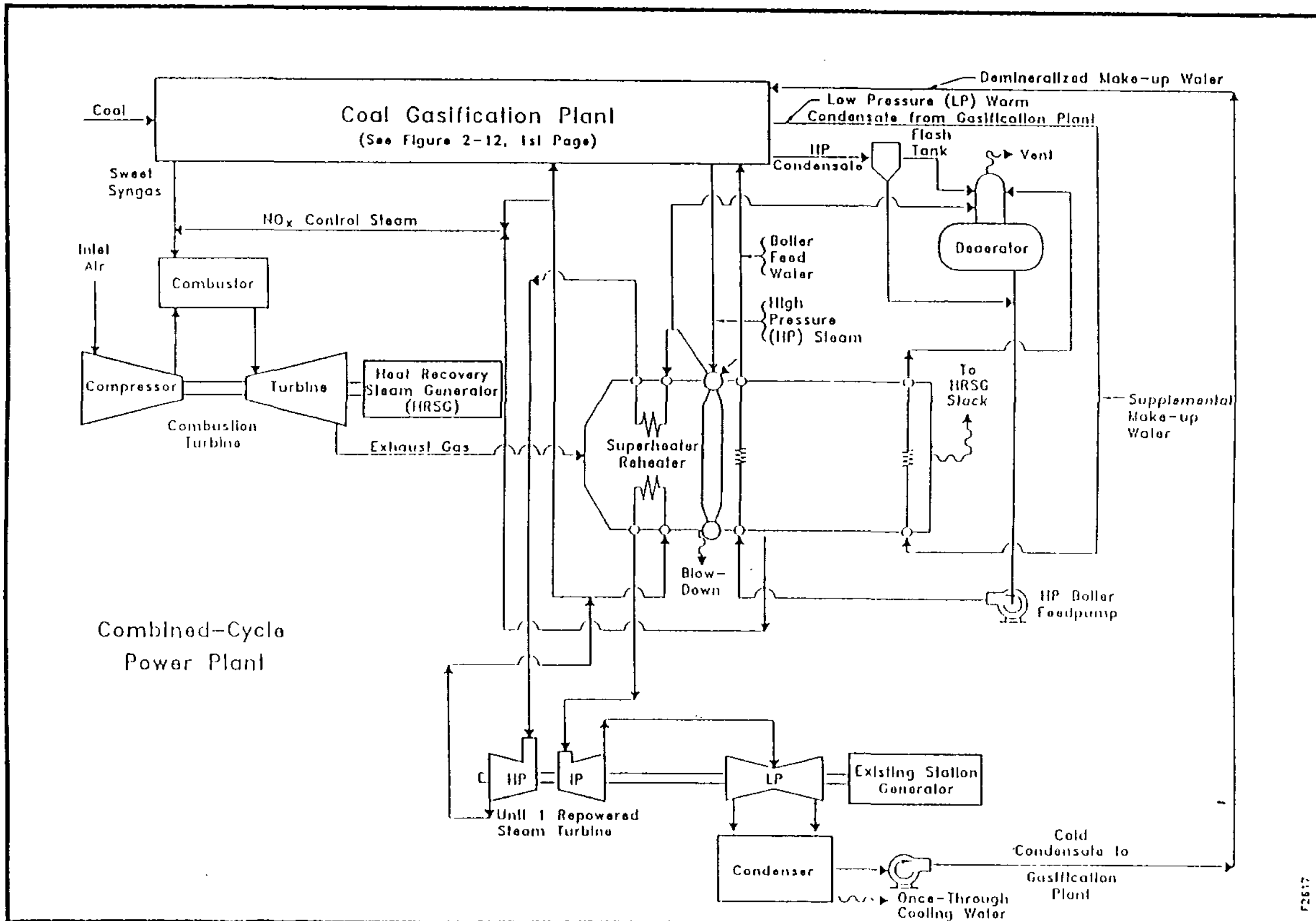


Figure 5A (Continued)

Block Flow Diagram

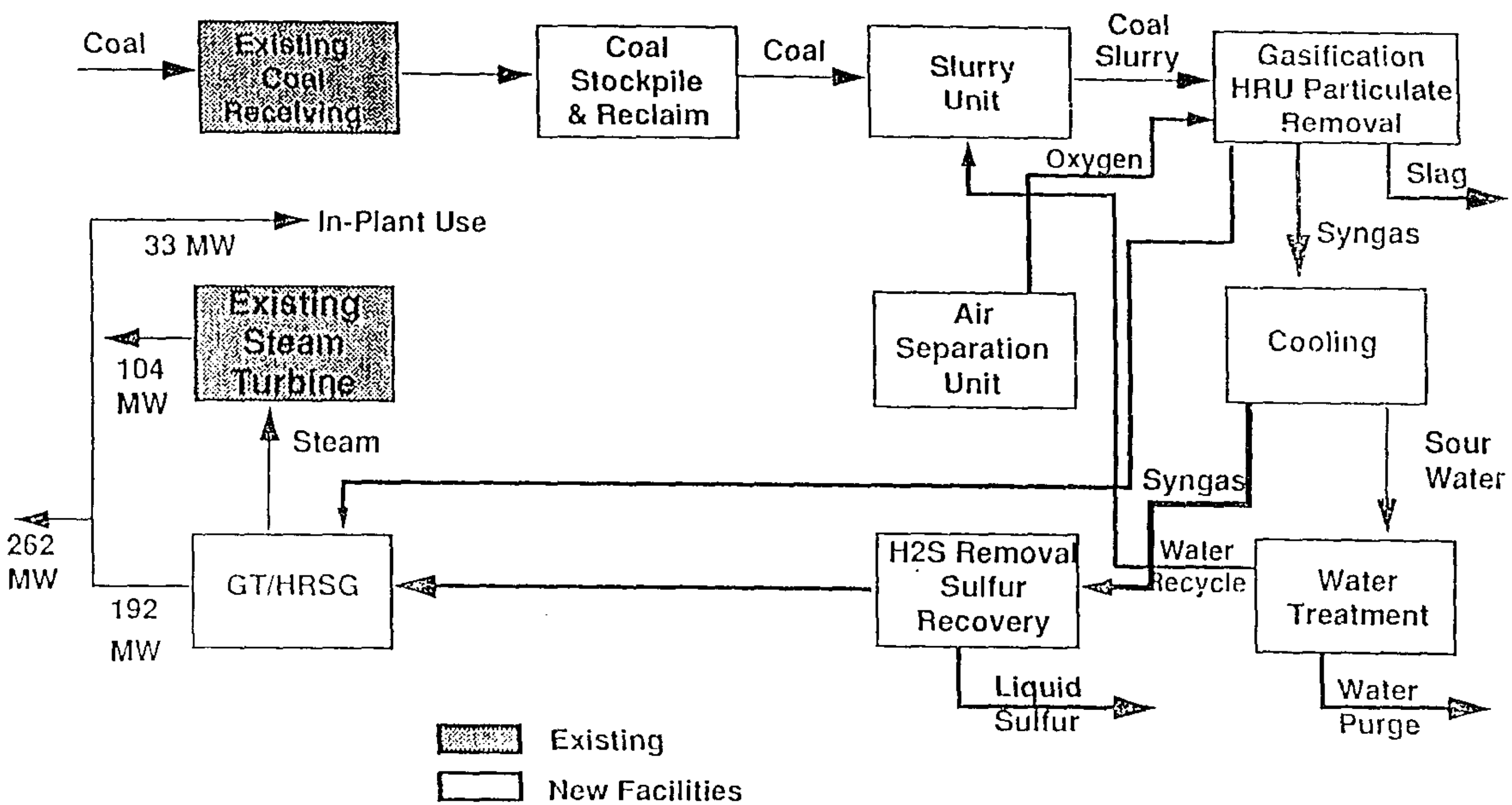


Figure 6

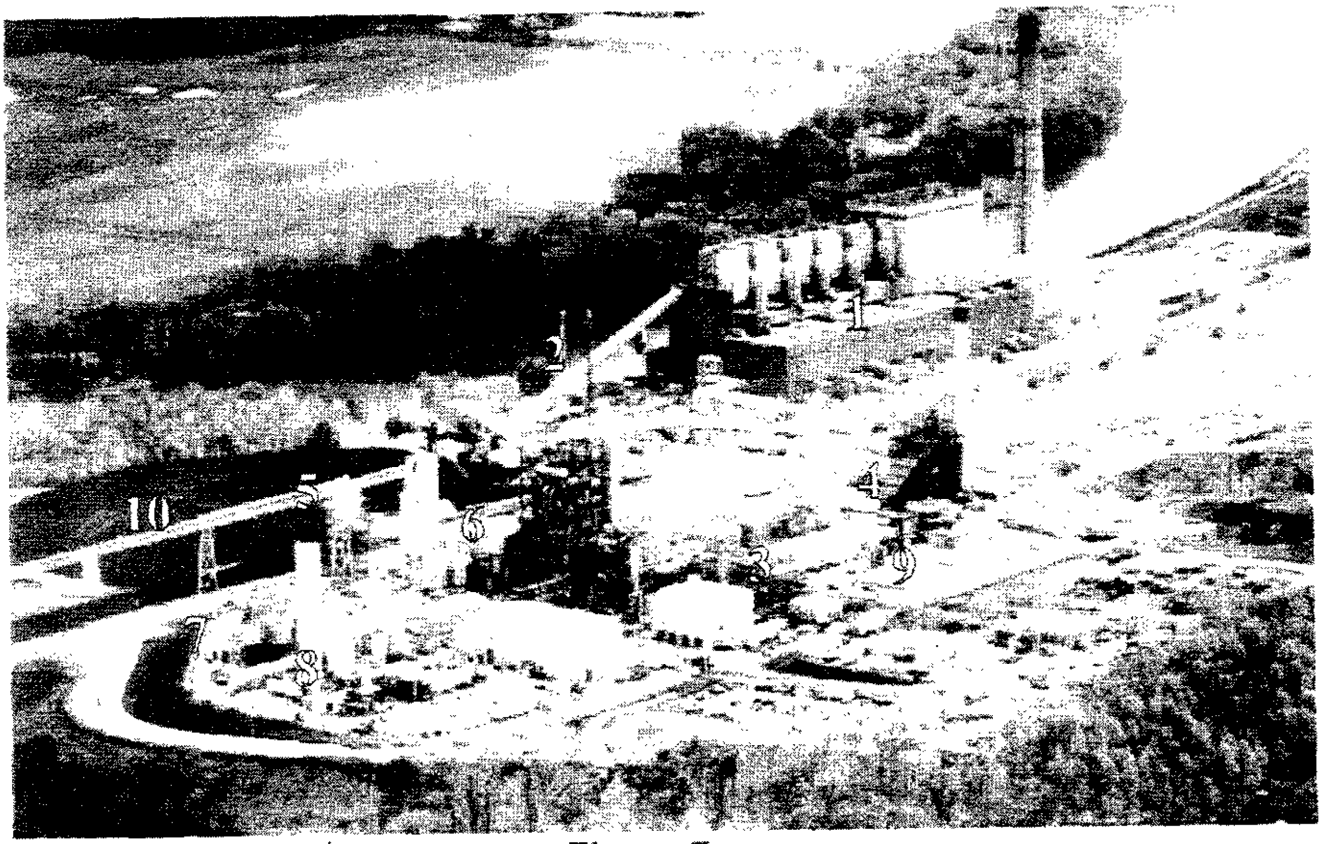


Figure 7

1. Existing Wabash Station
2. Existing coal transfer tower
3. Gas turbine building
4. Heat recovery steam generator
5. Coal receiving silo
6. Gasifier
7. Cooling Tower
8. Oxygen plant
9. New substation
10. Existing coal pile

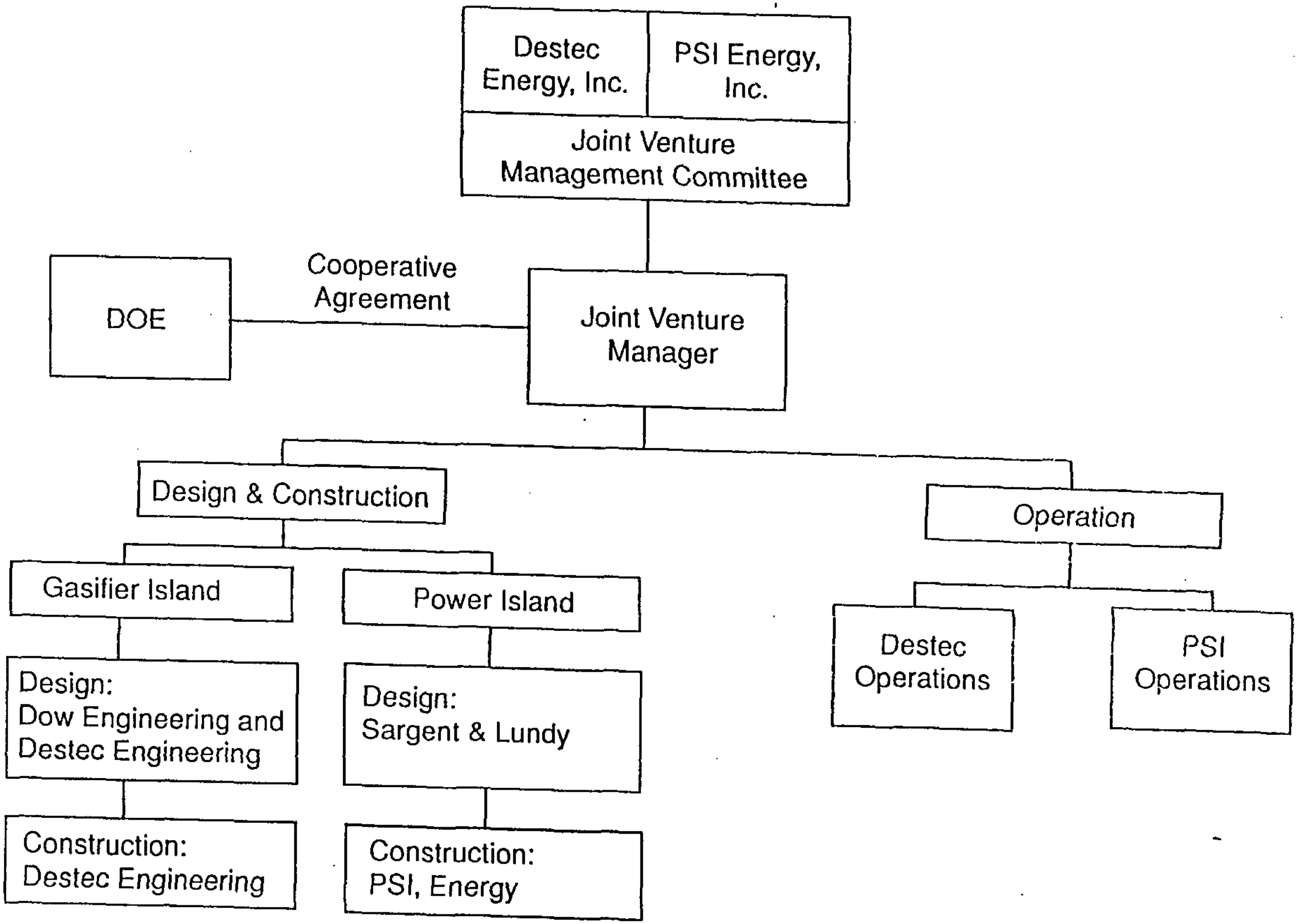


Figure 8 Project Organization

WABASH RIVER COAL GASIFICATION REPOWERING PROJECT

LIST OF PROJECT MILESTONES

Sept. 1998

WBS	MILESTONE	Nov. 1992 Proj. Mgmt. Plan Original Baseline	Nov. 1993 Proj. Eval. Plan Revised Baseline	June 2, 1995 Contin. Appl'n Revised Baseline	May 1996 Proj. Mgmt. Plan Current Baseline	Completion Date
1.1.04	Signing of Gasification Services Agreement	06/24/92	06/24/92	06/24/92	06/24/92	06/24/92
1.1.05	Completion of Funding	03/15/92	11/19/92	11/19/92	11/19/92	11/19/92
1.1.06	Receipt of Air Permits	03/01/93	05/28/93	05/27/93	05/27/93	05/27/93
	Receipt of NPDES Permit Modifications	12/01/92	12/01/92	12/06/93	12/06/93	12/06/93
1.1.07	NEPA Completion	10/01/92	05/28/93	05/28/93	05/28/93	05/28/93
1.1.08	Receipt of IURC Certificate of Need	03/01/93	05/26/93	05/26/93	05/26/93	05/26/93
1.1.10	Project Management					
	Project Management Plan	10/31/92	12/04/92	12/04/92	12/04/92	12/04/92
	Financing Plan & Licensing Agreements	02/28/93	04/30/93	04/30/93	04/30/93	04/30/93
	Project Definition & Preliminary Plant Design	02/28/93	03/15/93	03/15/93	03/15/93	03/15/93
	Continuation Application	02/28/93	05/05/93	05/28/93	05/28/93	05/28/93
	Formal Project Review	03/15/93	03/30/93	03/30/93	03/30/93	03/30/93
	Draft Environmental Monitoring Plan	04/30/93	03/31/93	03/31/93	03/31/93	03/31/93
1.1.13	DOE Award	07/27/92	07/27/92	07/27/92	07/27/92	07/27/92
1.1.30	Award of EPC Subcontract for Oxygen Plant	11/15/92	12/15/92	12/15/92	12/15/92	12/15/92
1.2.01	Project Management					
	Environmental Monitoring Plan	06/30/93	06/30/93	07/28/93	07/28/93	07/28/93
	40% Completion Formal Project Review	06/30/94	06/30/94	04/05/94	04/05/94	04/05/94
	90% Completion Formal Project Review	04/30/95	04/30/95	03/09/95	03/09/95	03/09/95
	Final Public Design Report	07/31/95	01/31/95	07/01/95	07/01/95	07/07/95
	Test Plan	05/25/95	05/25/95	07/01/95	07/01/95	07/08/95
	Plant Startup Plan	07/31/95	07/31/95	05/25/95	05/25/95	05/25/95

WABASH RIVER COAL GASIFICATION REPOWERING PROJECT

LIST OF PROJECT MILESTONES

Sept. 1998

WBS	MILESTONE	Nov. 1992 Proj. Mgmt. Plan **Original Baseline**	Nov. 1993 Proj. Eval. Plan **Revised Baseline**	June 2, 1995 Contin. Appl'n **Revised Baseline**	May 1996 Proj. Mgmt. Plan **Current Baseline**	**Completion Date**
	Continuation Application	07/31/95	01/31/95	06/02/95	06/02/95	06/02/95
1.2.04	Start of On-Site Dirtwork	12/01/92	06/01/93	06/01/93	06/01/93	06/01/93
	Release of Gasification Plant Site	09/01/93	09/10/93	09/17/93	09/17/93	09/17/93
1.2.05	Mobilization to Site	09/01/93	09/10/93	09/17/93	09/17/93	09/17/93
1.2.20	Award of High Temperature Heat Recovery Unit	11/01/92	11/03/92	11/03/92	11/03/92	11/03/92
	Award of Gasifier Vessels	01/10/93	01/21/93	01/21/93	01/21/93	01/21/93
	Jobsite Reciept of HTHRU	09/01/94	09/01/94	07/15/94	07/15/94	07/15/94
	Jobsite Reciept of Gasifier	07/01/94	07/01/94	05/15/94	05/15/94	05/15/94
1.2.22	Start of Foundation Work	09/15/93	10/08/93	10/08/93	10/08/93	10/08/93
	Setting of First Gasifier	09/01/94	09/01/94	06/08/94	06/08/94	06/08/94
	Setting of Second Gasifier	11/01/94	11/01/94	06/14/94	06/14/94	06/14/94
	Start of Refractory Installation	09/15/94	09/15/94	08/10/94	08/10/94	08/10/94
	Initial Firing with Coal	08/15/95	07/01/95	07/01/95	07/01/95	08/17/95
	Initial Delivery of Syngas	08/15/95	07/01/95	07/01/95	07/01/95	08/25/95
1.2.29	Completion of 100 Hour Test	10/01/95	08/15/95	08/15/95	11/18/95	11/18/95
1.2.30	Jobsite Receipt of Main Air Compressor	09/01/94	09/01/94	07/15/94	07/15/94	07/15/94
	Setting of Column	08/01/94	08/01/94	03/30/94	03/30/94	03/30/94
	Delivery of Oxygen	07/15/95	07/01/95	06/19/95	06/19/95	06/14/95
1.2.43	Construction Power/Water Available	09/01/93	10/06/93	10/20/93	10/20/93	10/20/93
1.2.50	Award of Coal Handling Subcontract	04/01/93	09/03/93	09/03/93	09/03/93	09/03/93
	Delivery of Coal to Syngas Facility	07/15/94	01/15/95	05/18/95	05/18/95	05/18/95
1.2.60	Award of STG Modification Subcontract	01/01/93	01/01/93	06/04/93	06/04/93	06/04/93

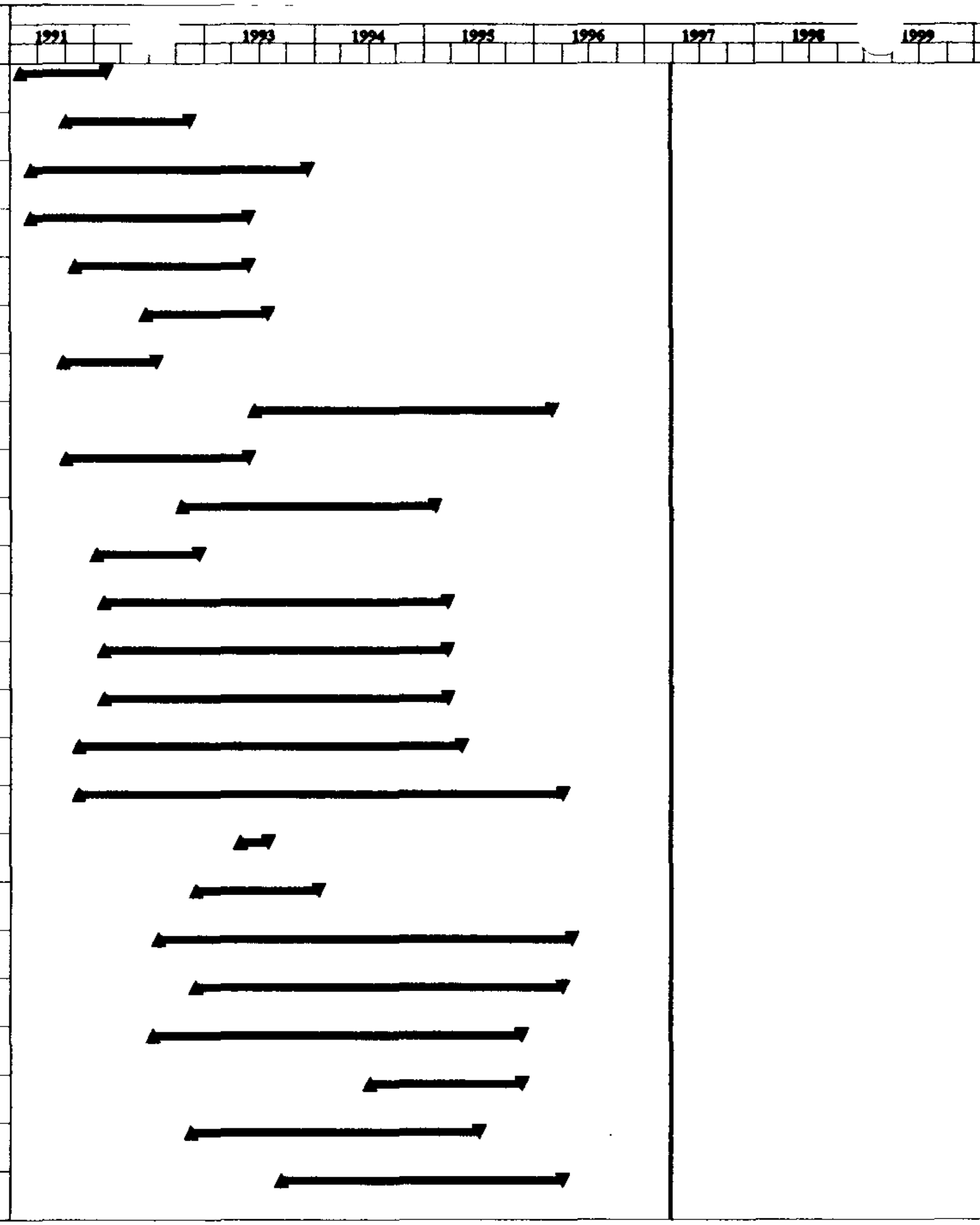
WABASH RIVER COAL GASIFICATION REPOWERING PROJECT

LIST OF PROJECT MILESTONES

Sept. 1998

WBS	MILESTONE	Nov. 1992 Proj. Mgmt. Plan **Original Baseline**	Nov. 1993 Proj. Eval. Plan **Revised Baseline**	June 2, 1995 Contin. Appl'n **Revised Baseline**	May 1996 Proj. Mgmt. Plan **Current Baseline**	**Completion Date**
1.2.70	Award of Gas Turbine Generator (GTG)	01/31/92	01/31/92	01/31/92	01/31/92	01/31/92
	Award of Heat Recovery Steam Generator (HRSG)	10/15/92	10/15/92	10/15/92	10/15/92	10/15/92
	Jobsite Delivery of GTG	03/01/94	01/01/94	03/18/94	03/18/94	03/18/94
1.2.75	Hydrotest of HRSG	04/15/95	04/15/95	03/31/95	03/31/95	03/31/95
	Synchronization of GTG	05/15/95	01/15/95	06/07/95	06/07/95	06/10/95
1.2.81	GTG Operation on Oil	01/01/95	01/01/95	06/07/95	06/07/95	06/09/95
	GTG Operation on Syngas	05/15/95	08/15/95	08/15/95	10/03/95	10/03/95
1.3.01	Project Management					
	Startup and Modification Report	12/01/95	12/01/95	11/01/95	01/01/99	
	Project Management Plan Update		not represented	11/01/95	05/01/96	05/16/96
	Formal Project Reviews	Annual				
	Draft Final Technical Report	07/31/98	07/31/98	09/30/98	01/01/99	
	Technology Performance & Economic Evaluation	11/30/98	11/30/98	10/01/98	02/01/99	
	Final Technical Report	12/31/98	12/31/98	11/30/98	02/28/99	

Activity ID	Activity Description	% Comp.	Early Start	Early Finish
1010	OVERALL PROJECT - SCOPE DEFINITION	100	01MAY91A	14FEB92A
1050	FINANCE/FUNDING	100	01OCT91A	15NOV92A
1060	PERMIT PREPARATION & SUBMITTAL	100	07JUN91A	06DEC93A
1070	NEPA PROCESS	100	07JUN91A	28MAY93A
1080	IURC APPROVAL	100	01NOV91A	26MAY93A
1100	PROJECT MANAGEMENT/ENVIRONMENTAL PLANS	100	19JUN92A	30JUL93A
1130	DOE COOPERATIVE AGREEMENT	100	16SEP91A	27JUL92A
1140	PROCESS CONSULTANTS & FEES	100	15JUN93A	29FEB96A
1200	GASIFICATION PLANT PROCESS DESIGN	100	01OCT91A	30MAY93A
1220	GASIFICATION PLANT AREA DESIGN	100	15OCT92A	01FEB95A
1300	OXYGEN PLANT PACKAGE DESIGN	100	10JAN92A	15DEC92A
1400	UTILITIES DESIGN	100	02FEB92A	15MAR95A
1500	COAL HANDLING DESIGN	100	01FEB92A	15MAR95A
1600	REPOWERING DESIGN	100	01FEB92A	15MAR95A
1700	GAS TURBINE AREA DESIGN	100	12NOV91A	01MAY95A
1900	POWER GENERATION PROJECT MGMT/COMMON ENGS	100	12NOV91A	01APR96A
2010	PROJECT MANAGEMENT PLAN	100	01MAY93A	30JUL93A
2040	SITE PREPARATION	100	01DEC92A	14JAN94A
2050	GASIFICATION PLANT CONST MANAGEMENT	100	01AUG92A	01MAY96A
2060	GAS TURBINE AREA CONSTRUCTION MANAGEMENT	100	01DEC92A	01APR96A
2150	GP PRE-OPERATIONS MANAGEMENT	100	12JUL92A	18NOV95A
2160	GT SELECTION & TRAINING PLANT OPERATORS	100	30JUN94A	18NOV95A
2200	GASIFICATION PLANT EQUIPMENT PROCUREMENT	100	15NOV92A	30JUN95A
2220	GASIFICATION PLANT CONSTRUCTION	100	13SEP93A	01APR96A



Project Start 01JUN91
Project Finish 01JUN99
Data Date 31MAR97
Run Date 11MAR98

Early Bar
Progress Bar
Critical Activity

6216

Sheet 1 of 2

DESTEC ENGINEERING, INC.
WABASH RIVER COAL GASIF REPOWER PROJ
DOE PROJECT PLAN

Figure 10

Activity ID	Activity Description	% Comp.	Early Start	Early Finish
2290	GAS PLANT ACCEPTANCE TESTING	100	25OCT95A	18NOV95A
2300	OXYGEN PLANT PROCUREMENT & CONSTRUCTION	100	15DEC92A	17FEB96A
2430	UTILITIES CONSTRUCTION	100	14JUN93A	01DEC94A
2500	COAL HANDLING PROCUREMENT & CONSTRUCTION	100	03MAY93A	01APR96A
2600	REPOWERING PROCUREMENT & CONSTRUCTION	100	04JUN93A	01APR96A
2700	GT AREA EQUIPMENT PROCUREMENT	100	31JAN92A	30NOV94A
2750	GAS TURBINE AREA CONSTRUCTION	100	13SEP93A	01APR96A
2810	GAS TURBINE ACCEPTANCE TESTING	100	01JUN95A	01APR96A
2990	PLANT PERFORMANCE TESTING	100	11OCT95A	18NOV95A
3010	PROJECT MANAGEMENT PLAN UPDATE	100	01DEC95A	16MAY96A
3060	ENVIRONMENTAL REPORTING	38	01DEC95A	01JUN99
3130	WARRANTY ADMINISTRATION	100	01DEC95A	02DEC96A
3140	GP COMMERCIAL OPERATION - DEMONSTRATION PERIOD	38	01DEC95A	01JUN99
3240	GT COMMERCIAL OPERATION - DEMONSTRATION PERIOD	100	01DEC95A	02DEC96A
11301PD	PRE AWARD PERIOD	100	16SEP91A	01AUG92A
11311BP	1ST BUDGET PERIOD	100	01AUG92A	30JUN93A
20402BD	2ND BUDGET PERIOD	100	30JUN93A	30NOV95A
30403BD	3RD BUDGET PERIOD	38	01DEC95A	01JUN99
11312PD	PHASE I DESIGN	100	01AUG92A	01FEB95A
20403PD	PHASE II CONSTRUCTION	100	01DEC92A	30NOV95A
30514PD	PHASE III OPERATION	38	01DEC95A	01JUN99

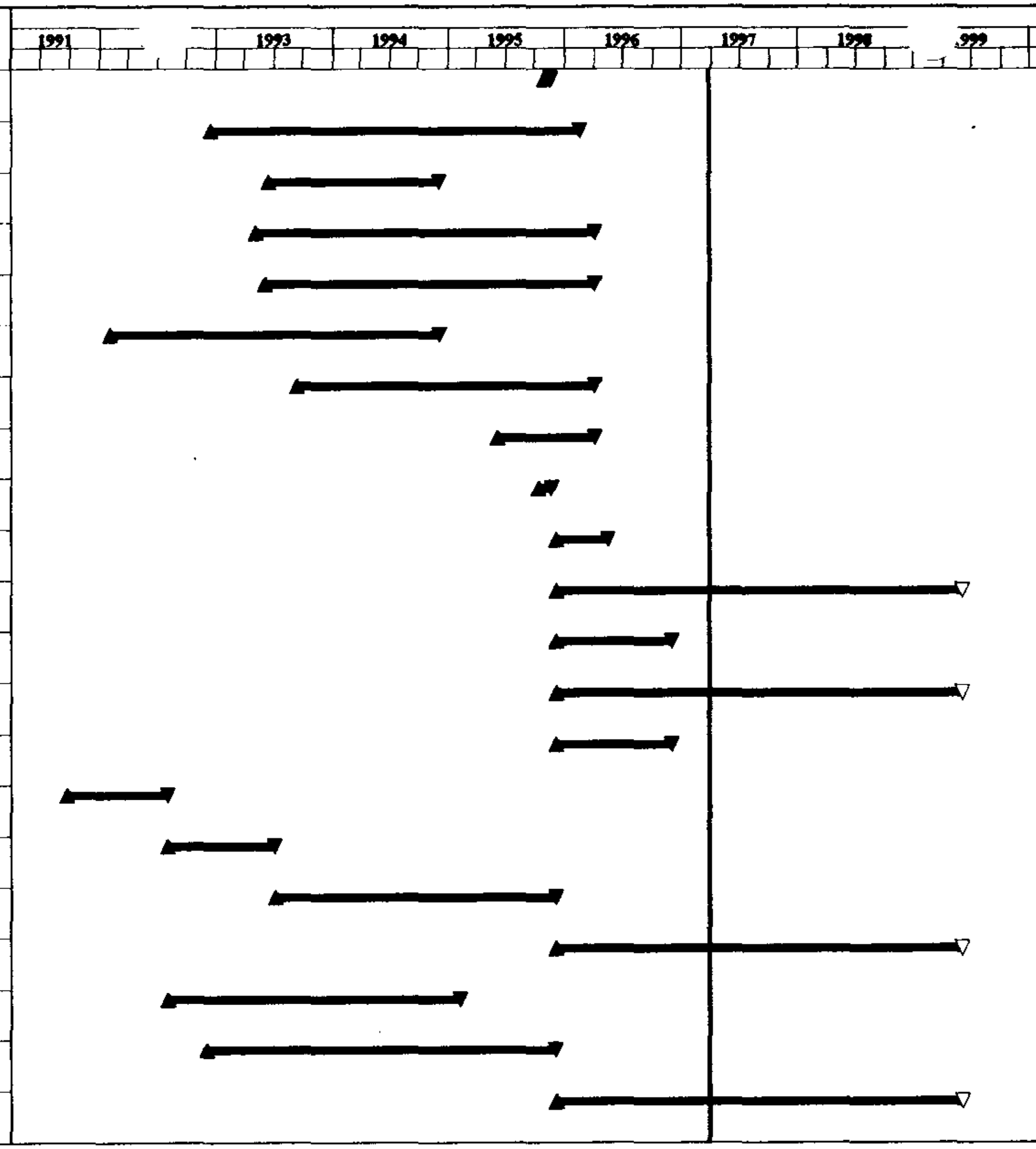


Figure 10

PLANT OPERATION STATISTICS
1996

GASIFICATION PLANT

PERFORMANCE DATA

Coal Gas Efficiency	70.5%
Gasifier on Coal (Hours)	1,902
Gasification Plant Capacity Factor (Produced)	17.7%
Gasification Plant Capacity Factor (Delivered)	14.7%

PRODUCTION DATA

Syngas on Spec (MMBtu)	2,769,683
1600# Steam (Mlbs)	820,624
Sulfur (Mlbs)	6,598
Slag, Moisture Free (Mlbs)	23,288

DELIVERED PRODUCTION

Actual Syngas Delivered (MMBtu)	2,296,486
1600# Steam (Mlbs)	726,887

MATERIAL/ENERGY USED

Coal, Moisture Free (Tons)	162,756
Coal (MMBtu)	4,080,140
Intermediate Pressure Steam (Mlbs)	124,229
Electrical Power, Total (MWh)	206,421
Oxygen, (Tons)	160,509
Fuel Gas (Mlbs)	22,031

POWER PLANT

PERFORMANCE DATA

Combustion Turbine Operating Hours (Syngas)	1,553
Combustion Turbine Operating Hours (Total)	2,177
Steam Turbine Operating Hours	1,900

PRODUCTION DATA

Combustion Turbine Generator (MWH)	6,650
Steam Turbine Generator (MWH)	4,627

Figure 11

APPENDIX C

List of Technical and Trade Publications Concerning WRCGRP

Appendix C
LISTING OF TECHNICAL PUBLICATIONS
(PUBLIC INFORMATION)

DATE	TITLE/SOURCE	AUTHOR(S)
November 1996	Clean Coal Technology, The Wabash River Coal Gasification Repowering Project	Amick/DOE
September 1996	Wabash River Coal Gasification Repowering Project, Project Early Commercial Operating Experience Pittsburgh Coal Conference	Amick, Breton Troxclair, Stultz
October 1996	Gasification Technology Conference EPRI/GTC San Francisco	Amick, Breton, Troxclair

APPENDIX D

Run Documentation and Production Graphs

Appendix D
Run Documentation and Production Graphs

Run Documentation
1st Commercial Year Downtime Analysis
Operational Run Periods for 1996
Monthly Plant Performance Data
1996 Cold Gas Efficiency
1996 Hours of Operation
1996 Gasifier Hours on Coal
1996 Produced Syngas
1996 1600# Steam Produced
1996 Sulfur Produced
1996 Slag Production
1996 Delivered Syngas
1996 Delivered #1600 LB Steam
1996 Feed to Gasifier
1996 Monthly Power Production
1996 Energy Utilization (Gasifier)
1996 Electrical Energy Utilization
1996 Coal Feed to Gasifier
1996 Total Sulfur Emissions
1996 Pounds of SO2/MMBtu of Coal Feed

1996 Run Documentation

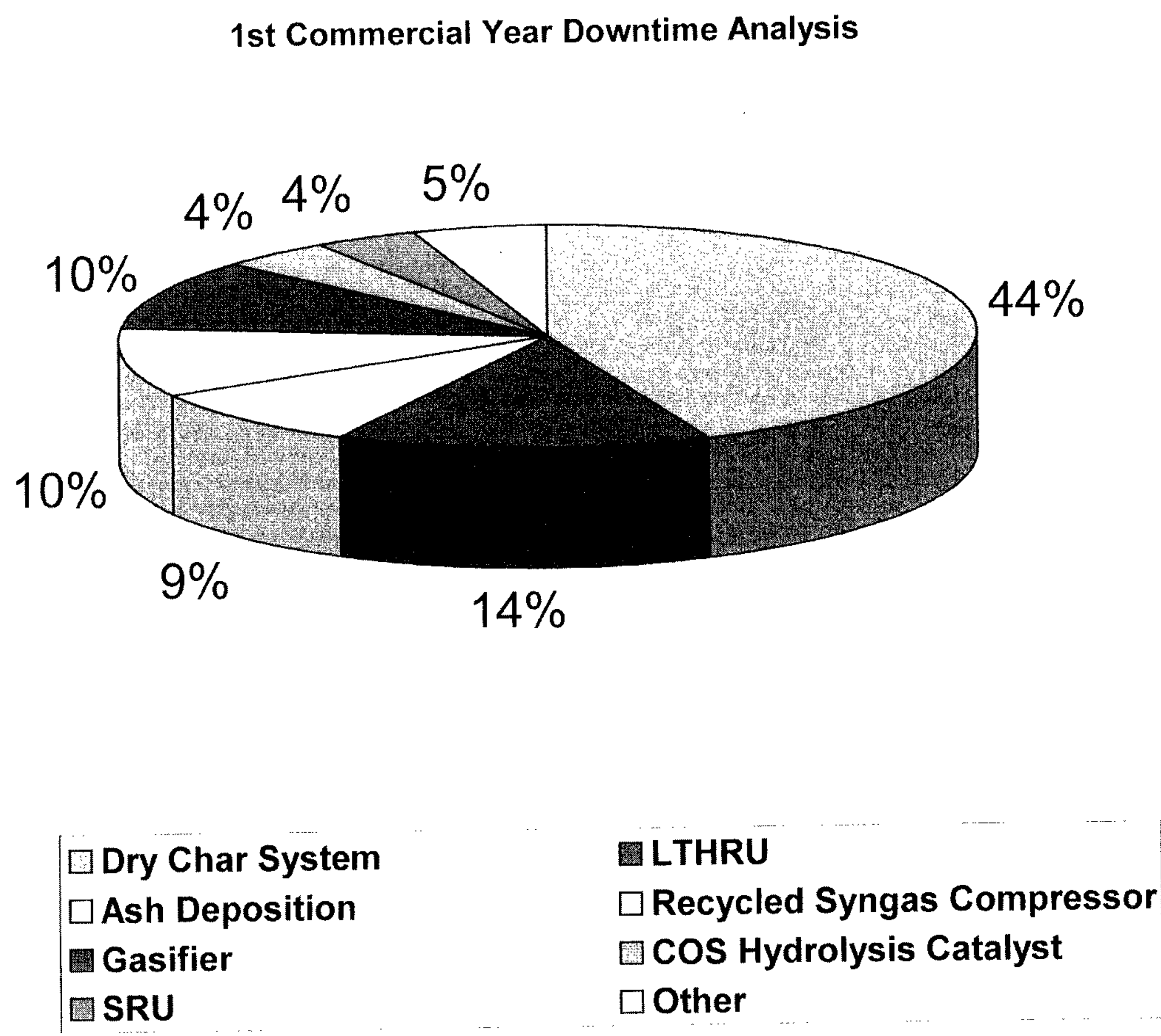
RUN	START	FINISH	DURATION	REASON FOR TERMINATION
JAN96A	1/4/96 14:28 Hours	1/4/96 14:57 Hours	0.48 Hours	Gasifier trip off coal due to control logic problem. High main burner differential pressure on M-120A
JAN96B	1/4/96 20:21 Hours	1/4/96 20:28 Hours	0.12 Hours	Transferred off coal operations due to high differential pressure indication on main slurry burner, M-120A. Commenced deslag
JAN96C	1/4/96 21:54 Hours	1/4/96 22:45 Hours	0.85 Hours	Transferred off coal operations due to high differential pressure indication on main slurry burner M-120A.
JAN96D	1/6/96 08:17 Hours	1/6/96 22:17 Hours	14.00 Hours	Transferred off coal operations at PSI request due to a Steam Turbine warm up vent valve packing failure
JAN96E	1/7/96 17:30 Hours	1/7/96 18:47 Hours	1.24 Hours	Gasifier trip off coal due to loss of PSI boiler feedwater to waste heat boiler
JAN96F	1/8/96 06:47 Hours	1/13/96 17:42 Hours	130.83 Hours	Transferred off coal operations upon completion of Bank Performance Test due to reduced rate operations caused by high waste heat boiler differential pressure
JAN96G	1/29/96 12:54 Hours	1/29/96 16:15 Hours	3.35 Hours	Transferred off coal operations due to a high vibration trip of the recycle syngas compressor
JAN96H	1/29/96 21:03 Hours	1/29/96 21:22 Hours	0.32 Hours	Transferred off coal operations due to a high vibration trip of the recycle syngas compressor
FEB96A	2/7/96 23:47 Hours	2/8/96 01:03 Hours	1.27 Hours	Gasifier trip on low level in waste heat boiler high pressure steam drum. Fluctuations caused by swinging boiler feedwater supply pressure
FEB96B	2/8/96 01:49 Hours	2/8/96 04:13 Hours	2.40 Hours	Transferred off coal operations due to blow-out of dry char recycle line to first stage reactor
FEB96C	2/10/96 01:58 Hours	2/17/96 07:27 Hours	173.48 Hours	Gasifier trip on low level in waste heat boiler high pressure steam drum after pressure transmitter failure
FEB96D	2/17/96 10:15 Hours	2/22/96 20:02 Hours	129.78 Hours	Transferred off coal operations due to continued reduced rate operations caused by high waste heat boiler differential pressure and high sulfur levels in product syngas

RUN	START	FINISH	DURATION	REASON FOR TERMINATION
MAR96A	3/12/96 21:43 Hours	3/13/96 01:50 Hours	4.12 Hours	Transferred off coal operations due to failure to obtain proper liquid sulfur flow into sulfur storage tank
MAR96B	3/14/96 05:03 Hours	3/20/96 00:53 Hours	139.83 Hours	Gasifier trip off coal due to loss of PSI boiler feedwater to waste heat boiler
MAR96C	3/24/96 07:23 Hours	3/24/96 08:03 Hours	0.67 Hours	Gasifier trip off coal due to high differential pressure on primary dry char filtration system
MAR96D	3/24/96 13:32 Hours	3/24/96 13:38 Hours	0.10 Hours	Transferred off coal operations due to ineffective backpulse pressure on primary dry char filtration system
MAR96E	3/24/96 15:53 Hours	3/26/96 03:24 Hours	35.52 Hours	Transferred off coal operations due to Sulfur Recovery Unit trip. Sheared linkage on tailgas incinerator feed valve.
MAR96F	3/27/96 09:38 Hours	3/27/96 11:08 Hours	1.5 Hours	Gasifier trip off coal due to loss of PSI boiler feedwater to waste heat boiler
MAR96G	3/27/96 12:54 Hours	3/27/96 13:10 Hours	0.27 Hours	Transferred off coal operations due to ineffective backpulse pressure on primary dry char filtration system
MAR96H	3/27/96 14:05 Hours	3/27/96 16:34 Hours	2.48 Hours	Transferred off coal operations after failure of main slurry burner, M-120A
MAR96I	3/29/96 20:27 Hours	3/29/96 22:03 Hours	1.60 Hours	Transferred off coal operations due to a failed rupture disk on P-110A
MAR96J	3/30/96 06:51 Hours	3/30/96 07:21 Hours	0.50 Hours	Gasifier trip off coal due to high differential pressure on primary dry char filtration system
MAR96K	3/30/96 09:10 Hours	3/30/96 10:23 Hours	1.22 Hours	Transferred off coal operations after failure of main slurry burner, M-120A
APR96A	4/6/96 10:41 Hours	4/6/96 22:23 Hours	11.70 Hours	Gasifier trip off coal due to loss of PSI boiler feedwater to waste heat boiler
APR96B	4/7/96 00:04 Hours	4/7/96 22:10 Hours	22.10 Hours	Transferred off coal operations due to high sulfur levels in product syngas. Root cause indicated as failure of E-160 tubes.

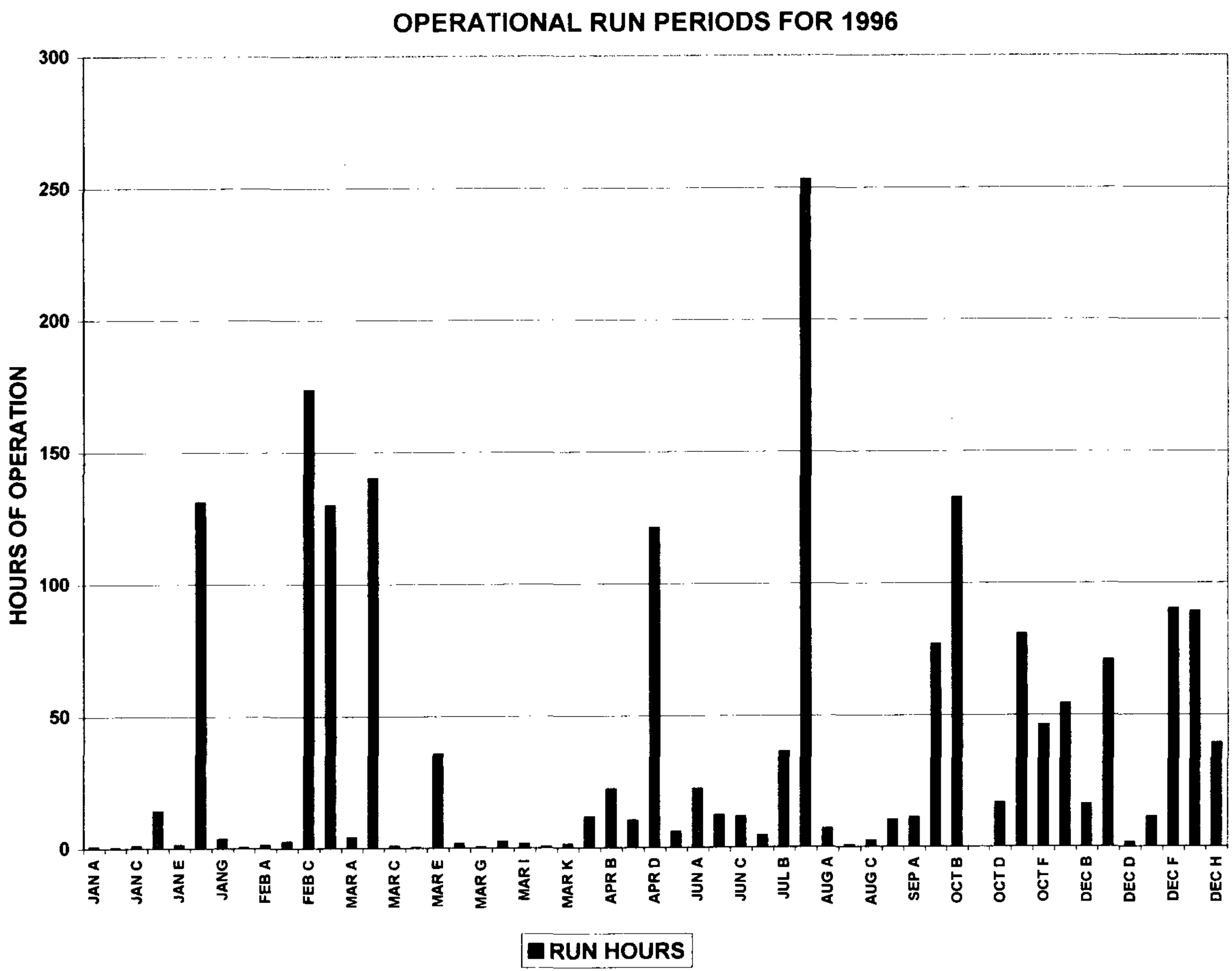
RUN	START	FINISH	DURATION	REASON FOR TERMINATION
APR96C	4/19/96 17:00 Hours	4/20/96 03:18 Hours	10.30 Hours	Transferred off of coal operations at PSI's request. Blown gasket on CT knockout drum during transfer to syngas on CT
APR96D	4/20/96 12:03 Hours	4/25/96 13:12 Hours	121.15 Hours	Transferred off of coal due to reduced rate operations caused by high waste heat boiler differential pressure
MAY96A	5/21/96 08:39 Hours	5/21/96 14:42 Hours	6.05 Hours	Transferred off of coal operations due to high differential pressure on the secondary Dry Char filtration system
JUN96A	6/1/96 00:00 Hours	6/1/96 06:15 Hours	22 Hours	Gasifier trip off of coal operations due to high differential pressure on the secondary Dry Char filtration system
JUN96B	6/26/96 10:02 Hours	6/26/96 22:12 Hours	12.17 Hours	Transferred off coal operations due to failure to obtain proper liquid sulfur flow into sulfur storage tank
JUN96C	6/27/96 09:58 Hours	6/27/96 21:33 Hours	11.58 Hours	Transferred off coal operations due to reduced rate operations caused by high waste heat boiler differential pressure
JUL96A	7/1/96 00:00 Hours	7/1/96 00:53 Hours	4.66 Hours	Transferred off coal operations due to a solenoid failure on a syngas vent valve at PSI
JUL96B	7/1/96 09:41 Hours	7/2/96 21:54 Hours	36.22 Hours	Gasifier Trip off of coal operations due to loss of coal slurry feed. P-102 discharge line plugged during swap procedure
JUL96C	7/5/96 22:49 Hours	7/16/96 11:56 Hours	253.12 Hours	Transferred off of coal operations due to syngas release caused by failed gasket at the R-160A/B outlet MBV, DI(234).
AUG96A	8/1/96 00:00 Hours	8/1/96 03:01 Hours	6.99 Hours	Transferred off of coal operations due to high differential pressure on the secondary Dry Char filtration system.
AUG96B	8/19/96 11:40 Hours	8/19/96 12:23 Hours	0.72 Hours	Transferred off of coal operations due to recycle syngas compressor trip.
AUG96C	8/25/96 19:42 Hours	8/25/96 22:05 Hours	2.38 Hours	Transferred off of coal operations due to recycle syngas compressor trip.
AUG96D	8/28/96 08:58 Hours	8/28/96 19:18 Hours	10.33 Hours	Transferred off of coal operations due to tar/char breakthrough into LTHR unit.

RUN	START	FINISH	DURATION	REASON FOR TERMINATION
SEP96A	9/30/96 10:51 Hours	10/1/96 00:00 Hours	13.15 Hours	
OCT96A	10/1/96 00:00 Hours	10/3/96 15:44 Hours	76.88 Hours	Gasifier trip on low level in waste heat boiler high pressure steam drum after pressure transmitter failure.
OCT96B	10/3/96 17:36 Hours	10/9/96 05:50 Hours	132.23 Hours	Transferred off coal operations due to failure of the G-121A slag crusher gearbox.
OCT96C	10/12/96 18:40 Hours	10/12/96 18:41 Hours	0.02 Hours	Transferred off coal operations due to a trip of the recycle syngas compressor on low 1st stage flow.
OCT96D	10/12/96 21:12 Hours	10/13/96 13:43 Hours	16.52 Hours	Transferred off of coal operations at PSI request due to failed stop ratio valve linkage.
OCT96E	10/13/96 17:17 Hours	10/17/96 01:58 Hours	80.68 Hours	Transferred off of coal operations at PSI request after unsuccessful swap to syngas on CT caused by PSI syngas valve problems.
OCT96F	10/18/96 14:52 Hours	10/20/96 13:03 Hours	46.18 Hours	Transferred off of coal operations due to piping failure within the Rx Device Cooling Water System.
DEC96A	12/10/96 16:25 Hours	12/12/96 22:38 Hours	54.22 Hours	Gasifier trip on low oxygen to fuel ratio after trip of the ASU main air compressor due to a 3rd stage guidevane malfunction.
DEC96B	12/16/96 16:57 Hours	12/17/96 08:50 Hours	15.88 Hours	Gasifier trip on a false "High Oxygen" indication from Analyzer A:AI(470).
DEC96C	12/17/96 11:09 Hours	12/20/96 09:56 Hours	70.78 Hours	Transferred off of coal operations due to a plugged overflow line on slag hopper T-140A.
DEC96D	12/20/96 17:16 Hours	12/20/96 18:45 Hours	1.48 Hours	Gasifier trip on Lo Waste Heat Boiler drum level after control logic problems due to freezing of HP steam flow transmitter to PSI.
DEC96E	12/20/96 21:03 Hours	12/21/96 08:06 Hours	11.05 Hours	Gasifier trip on a false "High Oxygen" indication from Analyzer A:AI(470).
DEC96F	12/21/96 11:42 Hours	12/25/96 05:52 Hours	90.17 Hours	Gasifier trip on high level in V-155A Primary Dry Char filtration vessel.

RUN	START	FINISH	DURATION	REASON FOR TERMINATION
DEC96G	12/26/96 08:52 Hours	12/30/96 01:55 Hours	89.05 Hours	Transferred off of coal operations after PSI CT trip while troubleshooting syngas leak. Off coal operations due to noise considerations.
DEC96H	12/30/96 08:47 Hours	1/1/97 00:00 Hours	39.22 Hours	Continuing



1st Commercial Year Downtime Analysis
44%
14%
9%
10%
10%
4%
4%
5%
Dry Char System
Ash Deposition
Gasifier
SRU
LTHRU
Recycled Syngas Compressor
COS Hydrolysis Catalyst
Other



OPERATIONAL RUN PERIODS FOR 1996
HOURS OF OPERATION
300
250
200
150
100
50
0
JAN A
JAN C
JAN E
JANG
FEB A
FEB C
MAR A
MAR C
MAR E
MAR G
MAR I
MAR K
APR B
APR D
JUN A
JUN C
JUL B
AUG A
AUG C
SEP A
OCT B
OCT D
OCT F
DEC B
DEC D
DEC F
DEC H
RUN HOURS

Monthly Plant Performance Data

	JAN	FEB	MAR	APR	MAY
PERFORMANCE DATA					
Coal Gas Efficiency	62.29	68.45	69.45	68.23	70.44
Gasifier on Coal (Hours)	151.18	307	188.55	165.29	21.8
PRODUCTION DATA					
Syngas on Spec (MMBtu)	218821	457091	297791	225047	14058
1600# Steam (Mlbs)	68219	134650	86241.4	64198	9945
Sulfur (Mlbs)	624	902	607	585	200
Slag, Moisture Free (Mlbs)	1818	3829	2454	1914	197
DELIVERED PRODUCTION					
Actual Syngas Delivered (MMBtu)	166496	377304	249531	183002	7141.6
1600# Steam (Mlbs)	62446	129039	76841	56905	4147
MATERIAL/ENERGY USED					
Coal, Moisture Free (Tons)	14565	30601	19755	15069	1549
Coal (MMBtu)	362758	768387	496058	379743	39046
Intermediate Pressure Steam (Mlbs)	13303	14353	13669	19294	6458
Electrical Power, Total (MWh)	18034	18853	19835	19993	13970
Oxygen, (Tons)	14590	26159	18006	13387	2310
Fuel Gas (Mlbs)	2658	2617	3631	2167	1973
PLANT EMISSION DATA					
Average Total Sulfur in Syngas (ppm)	116	216.3	169.65	175.91	59.52
Total SO2 Emissions (lbs)	87830	153881	66695	65968	3081
SO2, (Total Plant lbs/MMBtu of Coal Feed)	0.24	0.227	0.145	0.173	0.078
POWER PLANT PRODUCTION DATA					
Combustion Turbine Generator (MWh)	27105	72754	77071	39760	59145
Steam Turbine Generator (MWh)	12282	36843	37175	18501	30174
Total Gross Generation (MWh)	39387	109597	114246	58261	89319
Total Syngas Generation (MWh)	27830	27830	107338	53755	82957

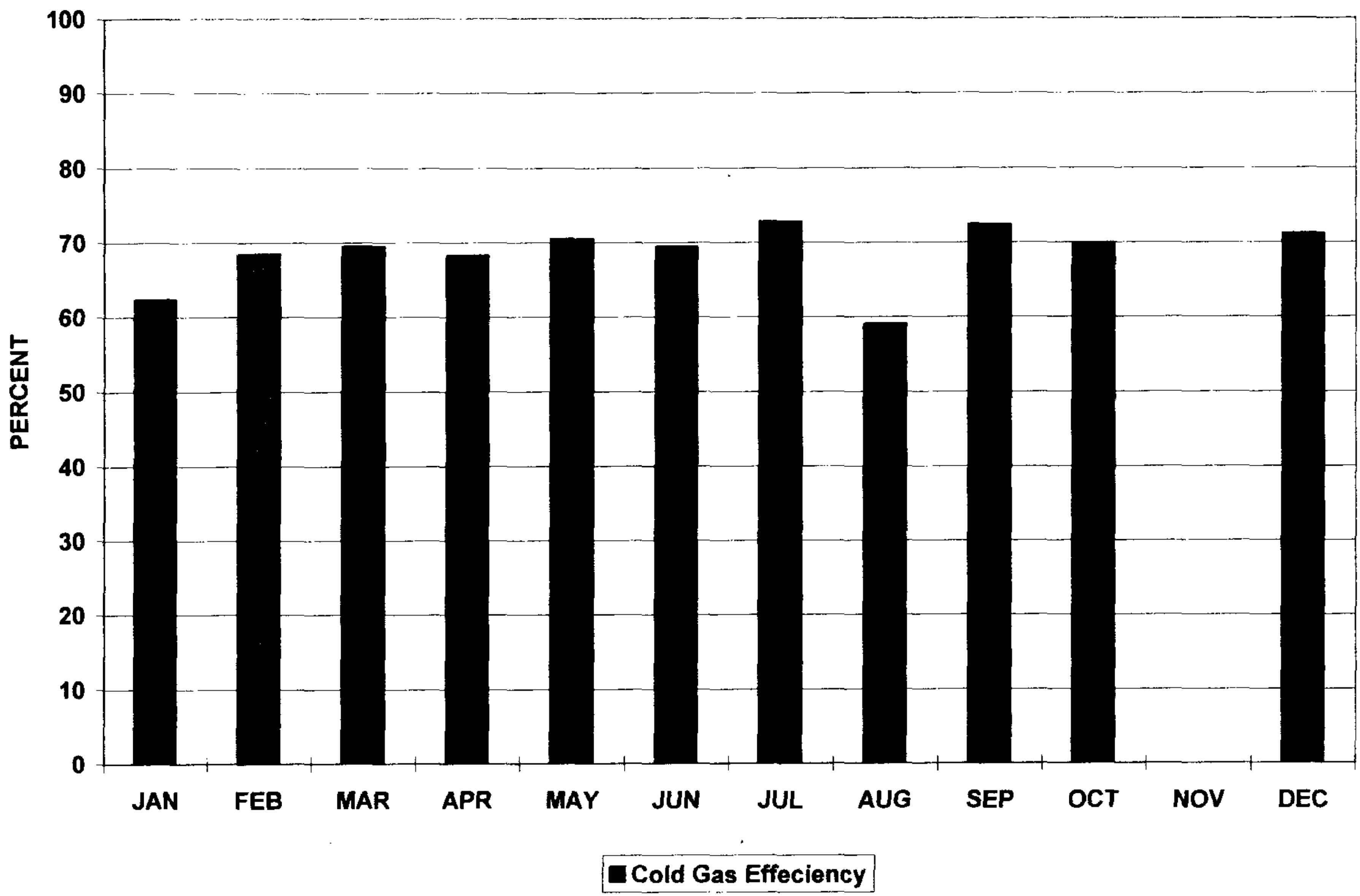
Monthly Plant Performance Data

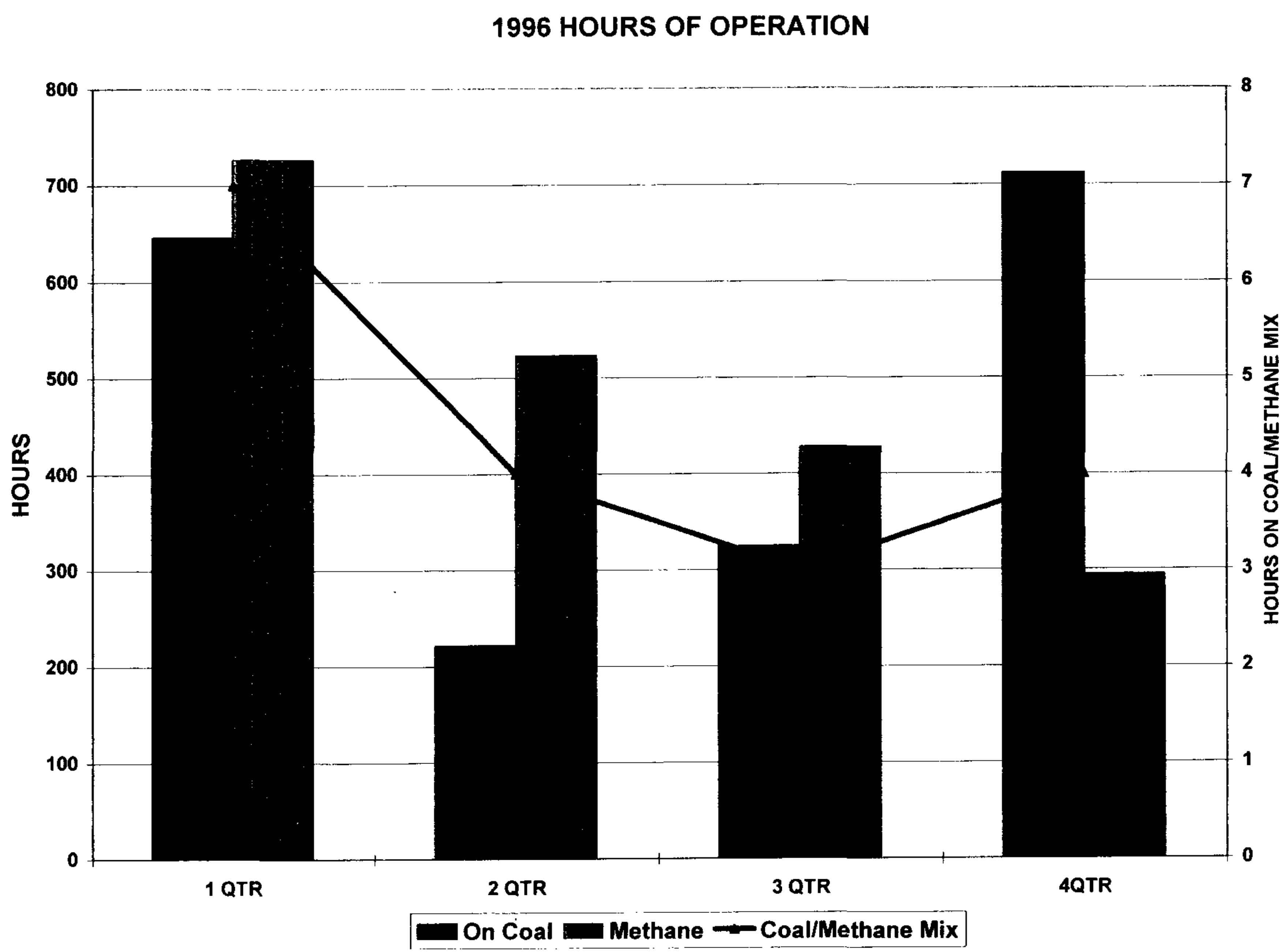
	JUN	JUL	AUG	SEP	OCT
PERFORMANCE DATA					
Coal Gas Efficiency	69.4	72.72	59.04	72.32	69.7
Gasifier on Coal (Hours)	33.91	293.61	16.4	13.16	339.43
PRODUCTION DATA					
Syngas on Spec (MMBtu)	42352	446012	18679	15374	480007
1600# Steam (Mlbs)	13496	125484	8053	6075	144265
Sulfur (Mlbs)	64.6	881	42	39	1183
Slag, Moisture Free (Mlbs)	356	3687	160	139	4006
DELIVERED PRODUCTION					
Actual Syngas Delivered (MMBtu)	13564	418404	9609	12126	404169
1600# Steam (Mlbs)	7706	119883	4121	4359	126221
MATERIAL/ENERGY USED					
Coal, Moisture Free (Tons)	2734	28746	1480	1101	32099
Coal (MMBtu)	69369	616788	31759	23613	688725
Intermediate Pressure Steam (Mlbs)	5437	12524	7750	-7708	-4877
Electrical Power, Total (MWh)	11726	22679	16423	12722	20387
Oxygen, (Tons)	3218	24256	2214	1472	25671
Fuel Gas (Mlbs)	1390	1902	1111	487.7	1760
PLANT EMISSION DATA					
Average Total Sulfur in Syngas (ppm)	97.04	183.2	102.63	12.51	23.53
Total SO2 Emissions (lbs)	7933	119105	8325	1773	21547
SO2, (Total Plant lbs/MMBtu of Coal Feed)	0.114359	0.182	0.267	0.072	0.031
POWER PLANT PRODUCTION DATA					
Combustion Turbine Generator (MWh)	53235	70501	108784	70671	30132
Steam Turbine Generator (MWh)	26409	35912	55249	37350	16012
Total Gross Generation (MWh)	79644	106413	164033	108021	46144
Total Syngas Generation (MWh)	67781	99191	106411	101672	44042

Monthly Plant Performance Data

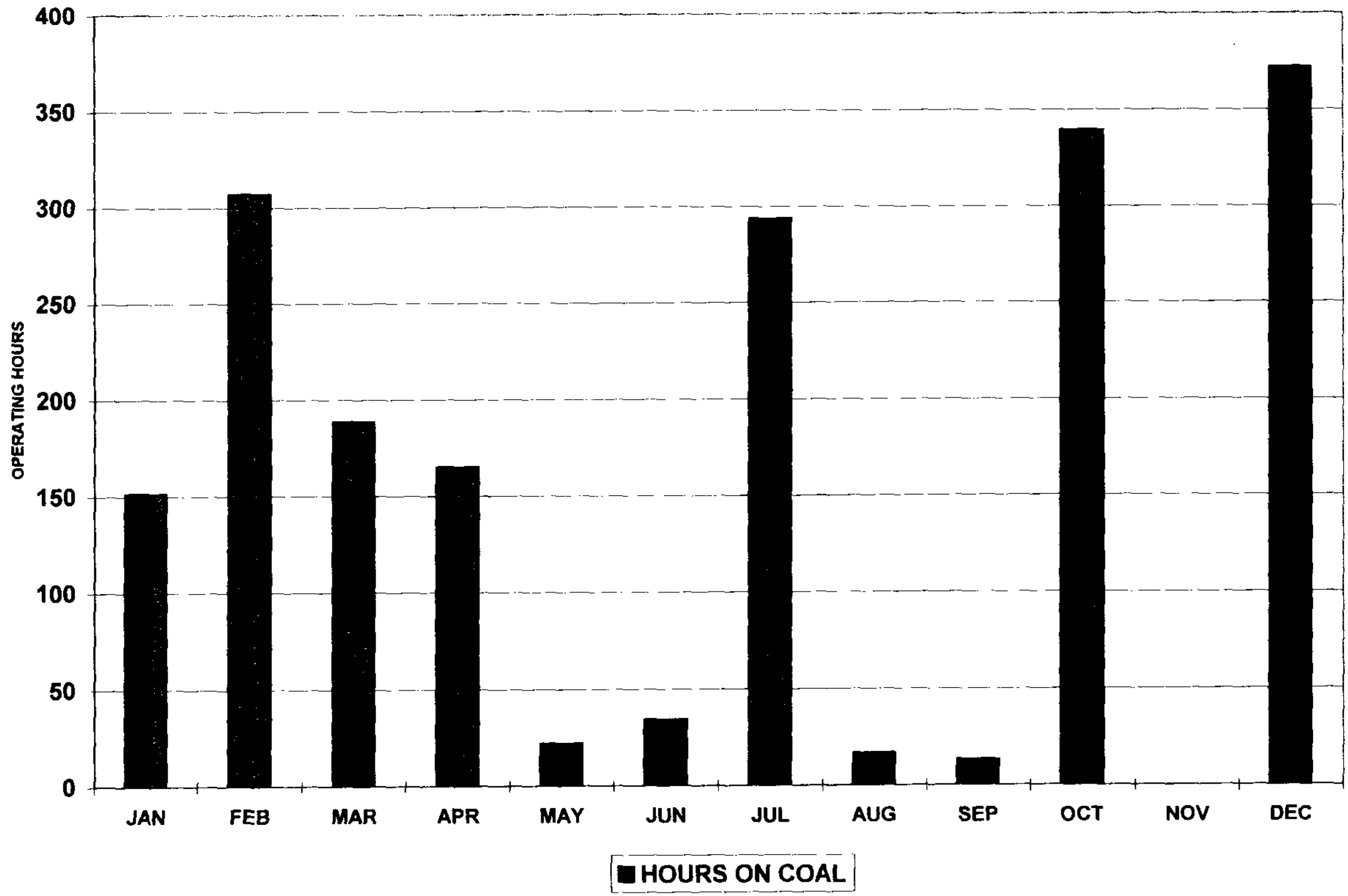
	NOV	DEC
PERFORMANCE DATA		
Coal Gas Efficiency	0	71.1
Gasifier on Coal (Hours)	0	371.87
PRODUCTION DATA		
Syngas on Spec (MMBtu)	0	554451
1600# Steam (Mlbs)	0	159997
Sulfur (Mlbs)	0	1451
Slag, Moisture Free (Mlbs)	0	4728
DELIVERED PRODUCTION		
Actual Syngas Delivered (MMBtu)	0	455139
1600# Steam (Mlbs)	0	135218
MATERIAL/ENERGY USED		
Coal, Moisture Free (Tons)	0	36682
Coal (MMBtu)	0	787040
Intermediate Pressure Steam (Mlbs)	2714	13244
Electrical Power, Total (MWh)	9269	22660
Oxygen, (Tons)	56	29234
Fuel Gas (Mlbs)	48	826
PLANT EMISSION DATA		
Average Total Sulfur in Syngas (ppm)	0	101.73
Total SO2 Emissions (lbs)	0	65298
SO2, (Total Plant lbs/MMBtu of Coal Feed)	0	0.079
POWER PLANT PRODUCTION DATA		
Combustion Turbine Generator (MWh)	66918	48978
Steam Turbine Generator (MWh)	31639	24277
Total Gross Generation (MWh)	98577	73255
Total Syngas Generation (MWh)	75931	69437

1996 COLD GAS EFFICIENCY

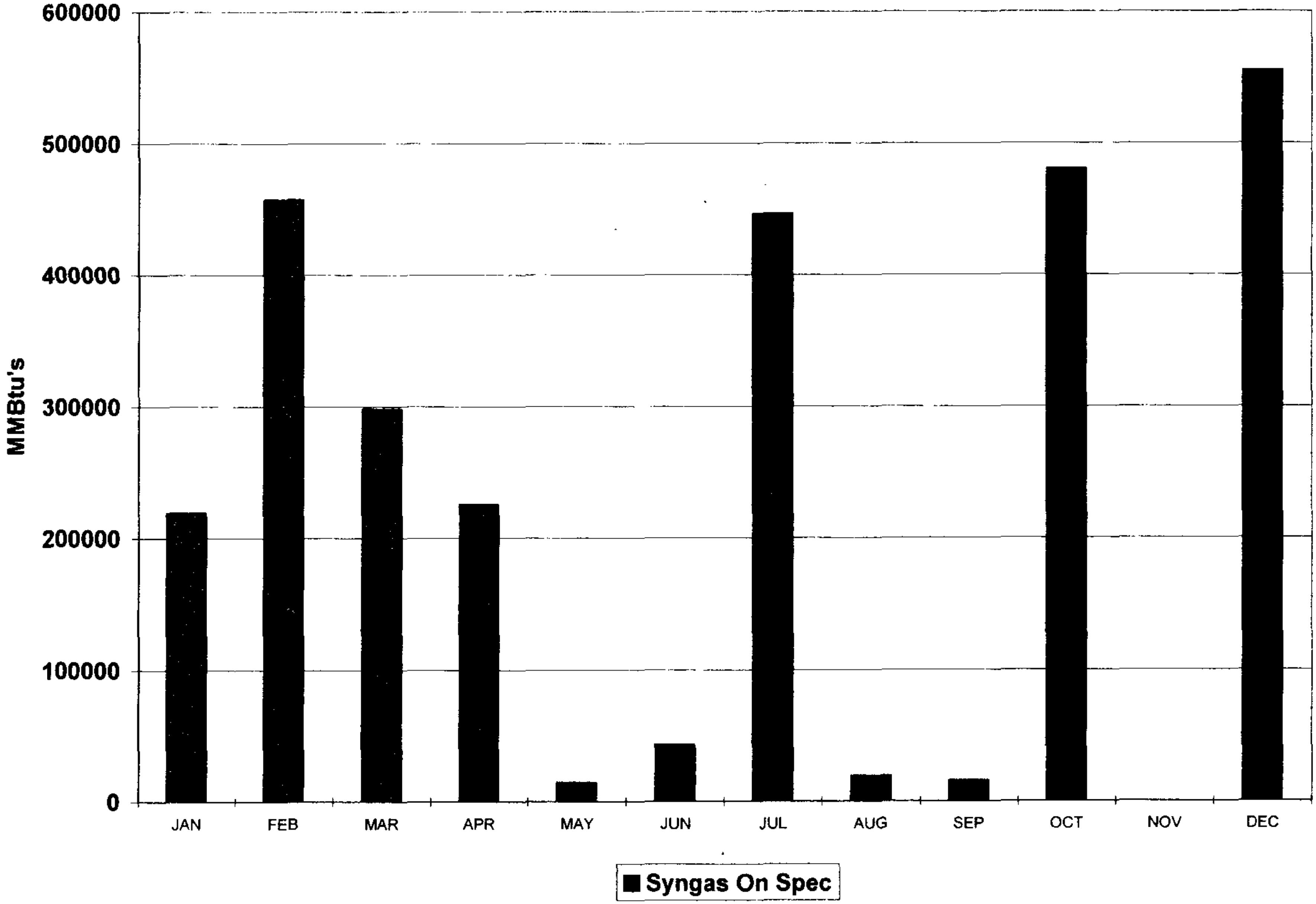


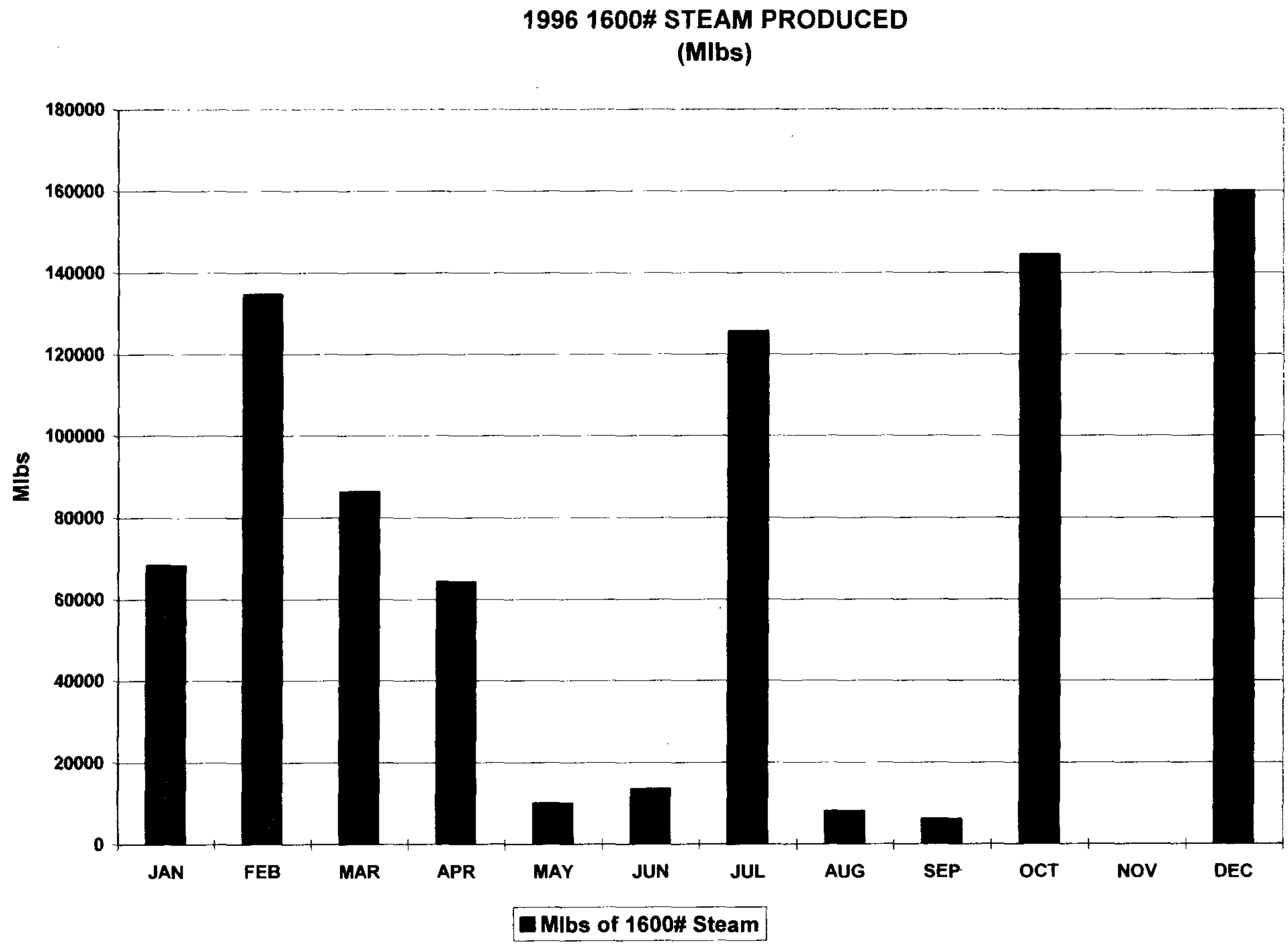

1996 HOURS OF OPERATION
HOURS
800
700
600
500
400
300
200
100
0
1 QTR
2 QTR
3 QTR
4QTR
HOURS ON COAL/METHANE MIX
8
7
6
5
4
3
2
1
0
On Coal
Methane
Coal/Methane Mix

1996 GASIFIER HOURS ON COAL

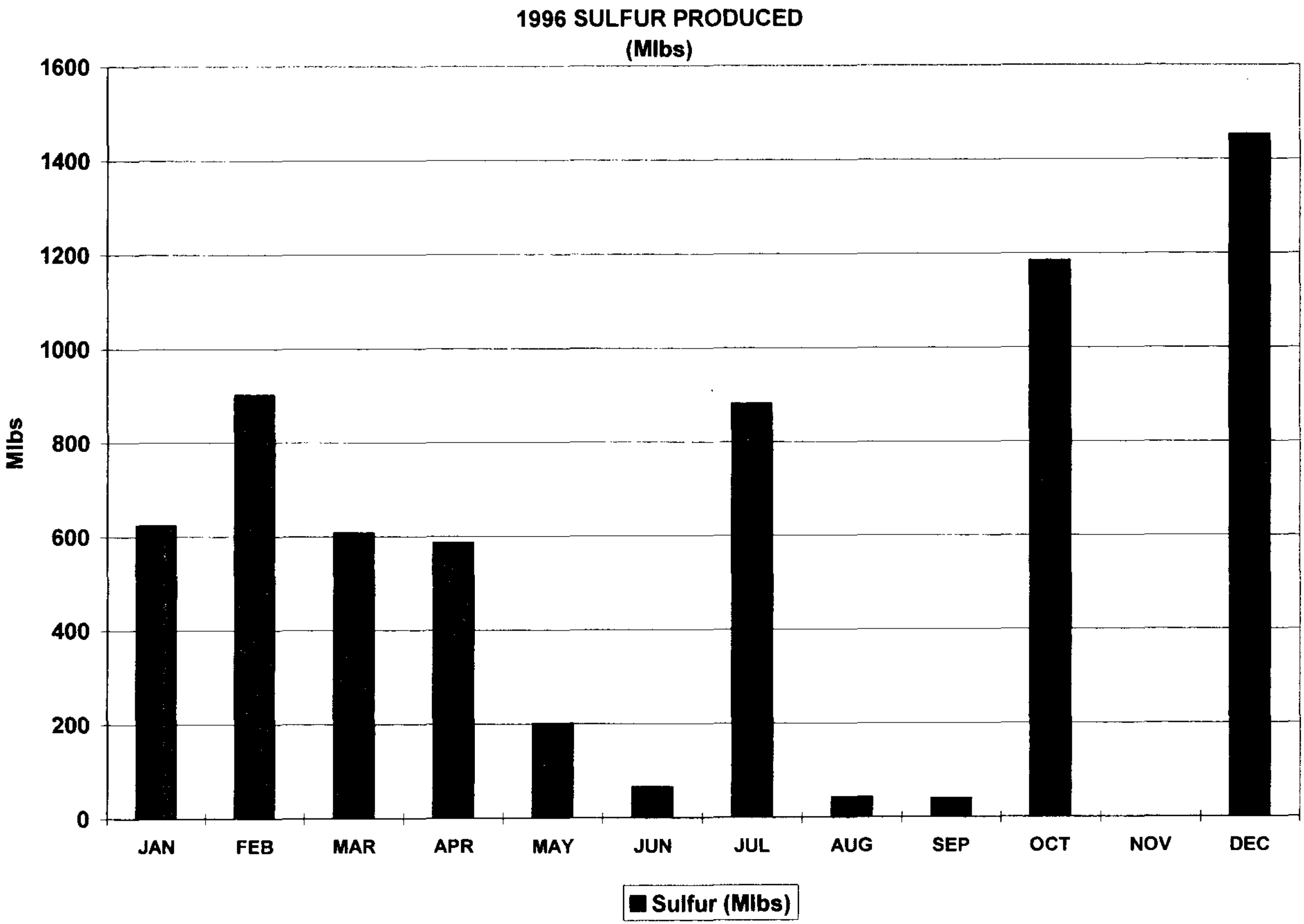


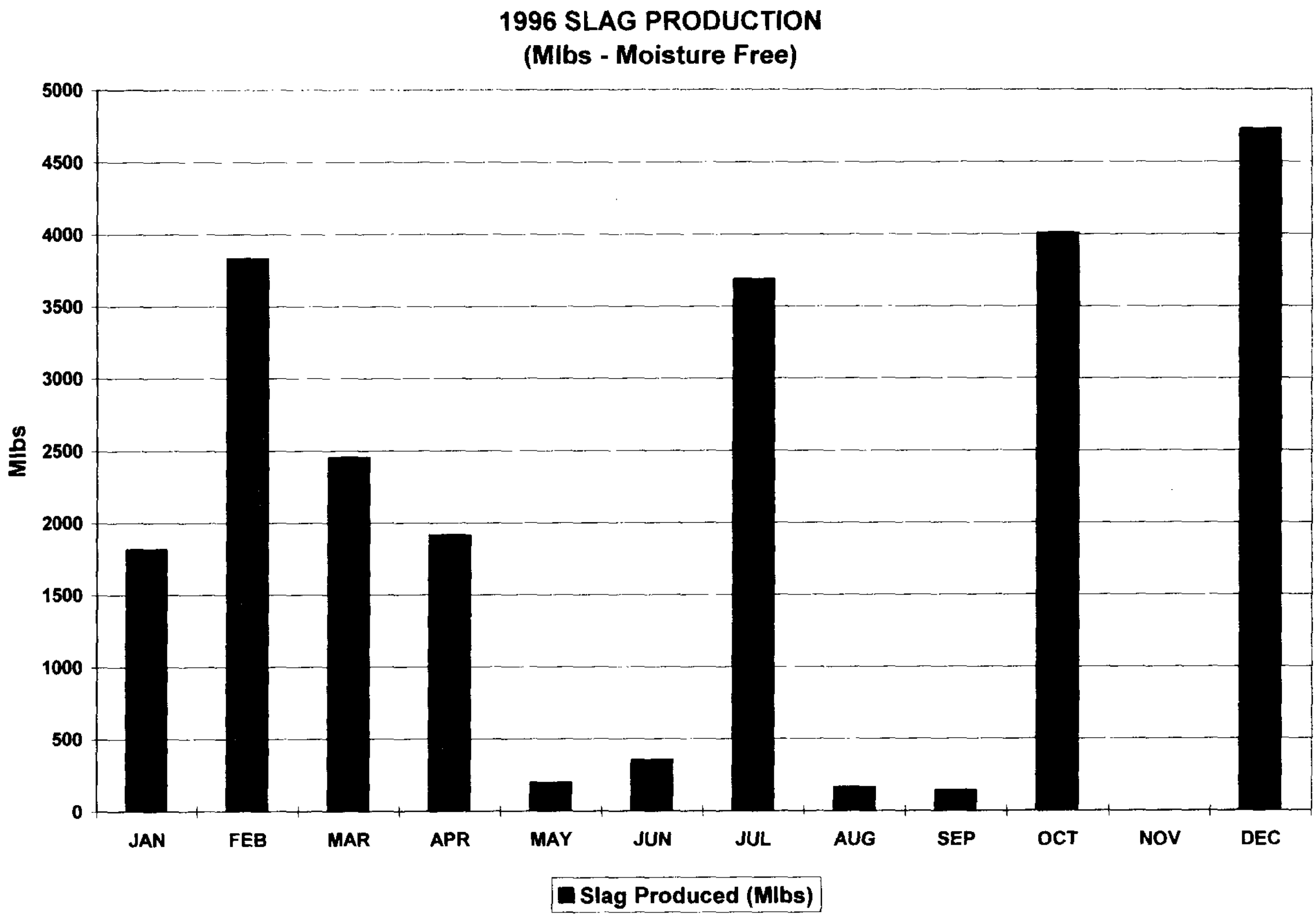
1996 PRODUCED SYNGAS
(ON-SPECIFICATION)



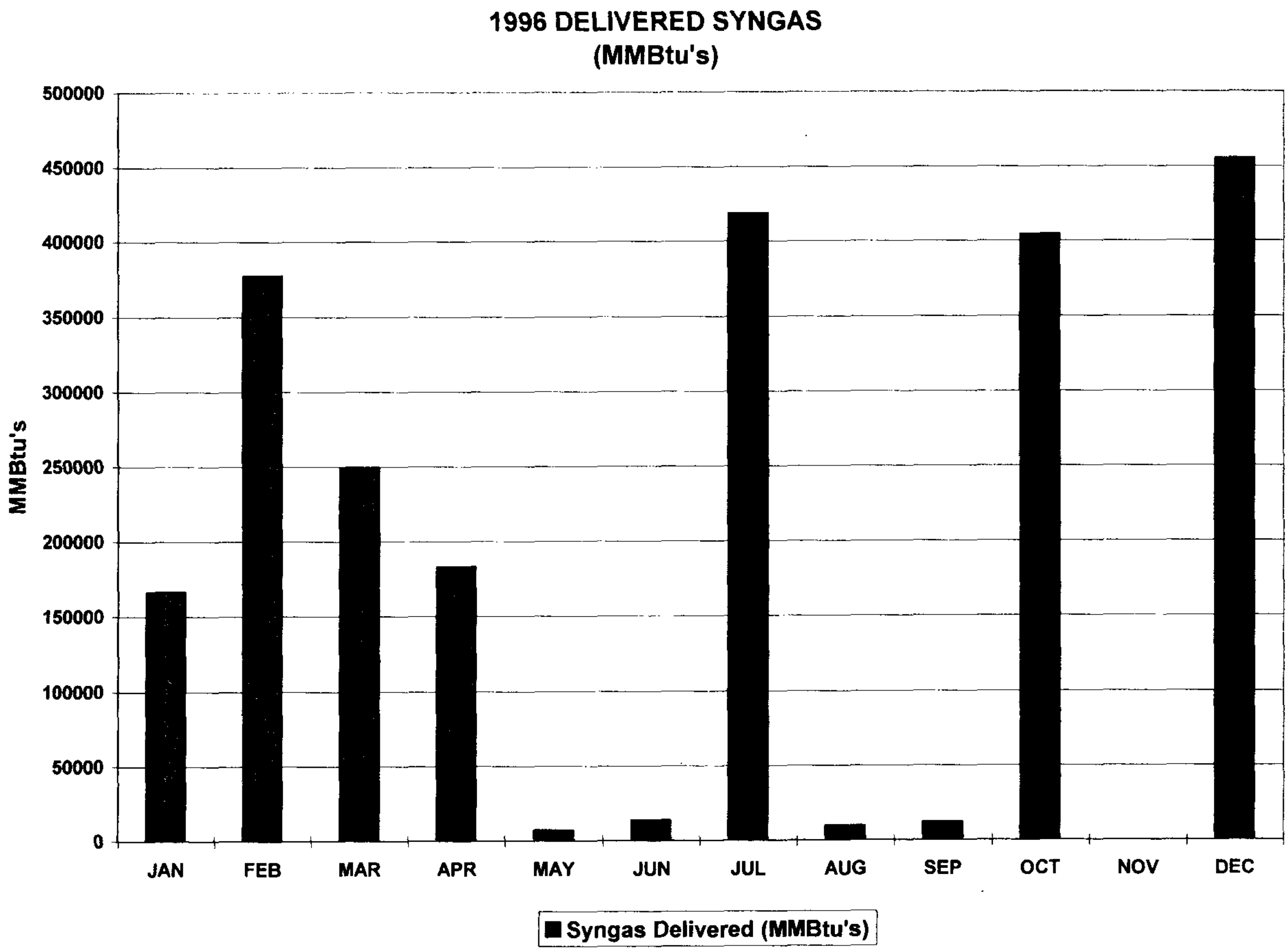


1996 1600# STEAM PRODUCED
(Mlbs)
Mlbs
180000
160000
140000
120000
100000
80000
60000
40000
20000
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
Mlbs of 1600# Steam

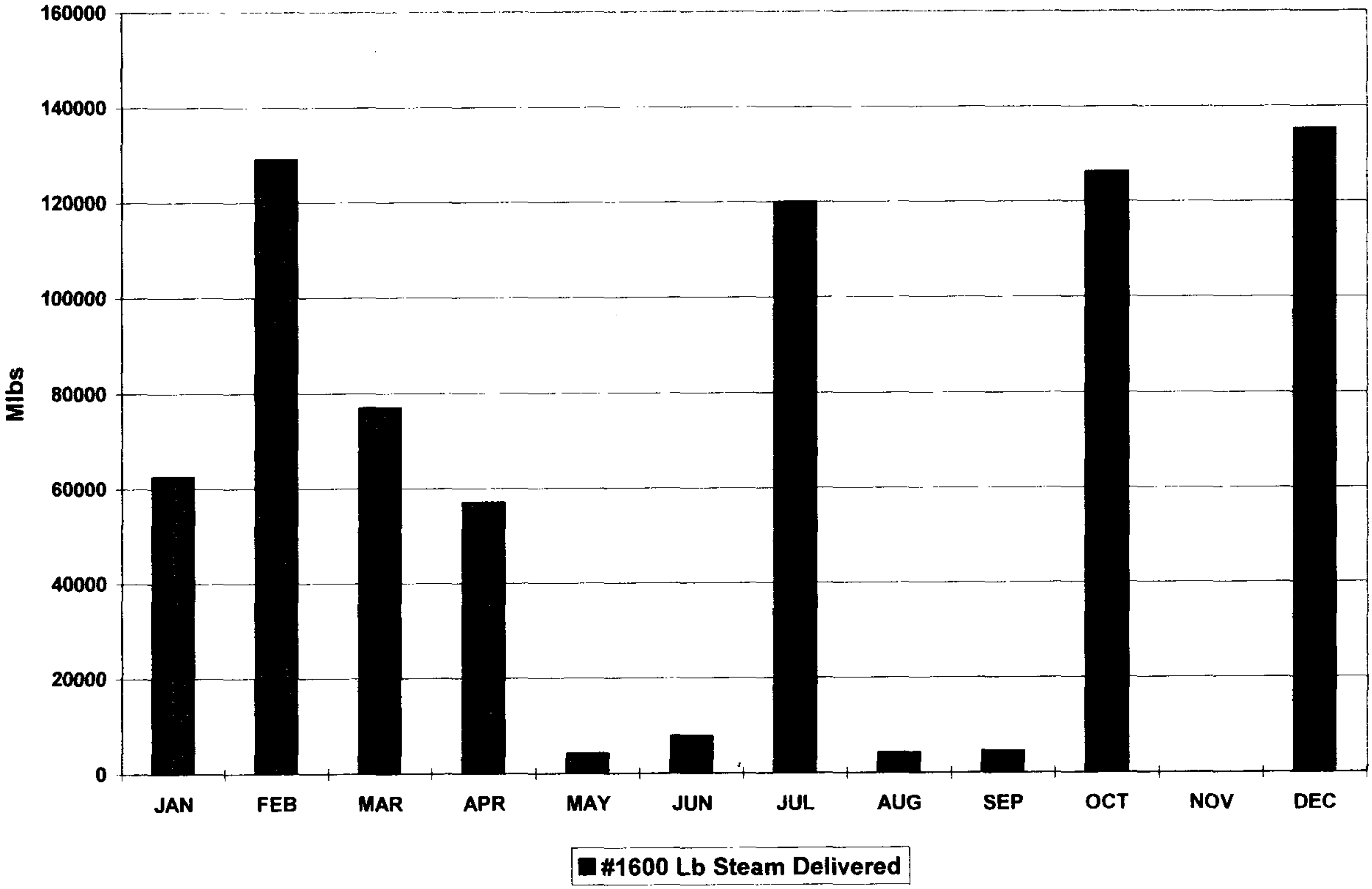

1996 SULFUR PRODUCED
(Mlbs)
Mlbs
1600
1400
1200
1000
800
600
400
200
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
Sulfur (Mlbs)

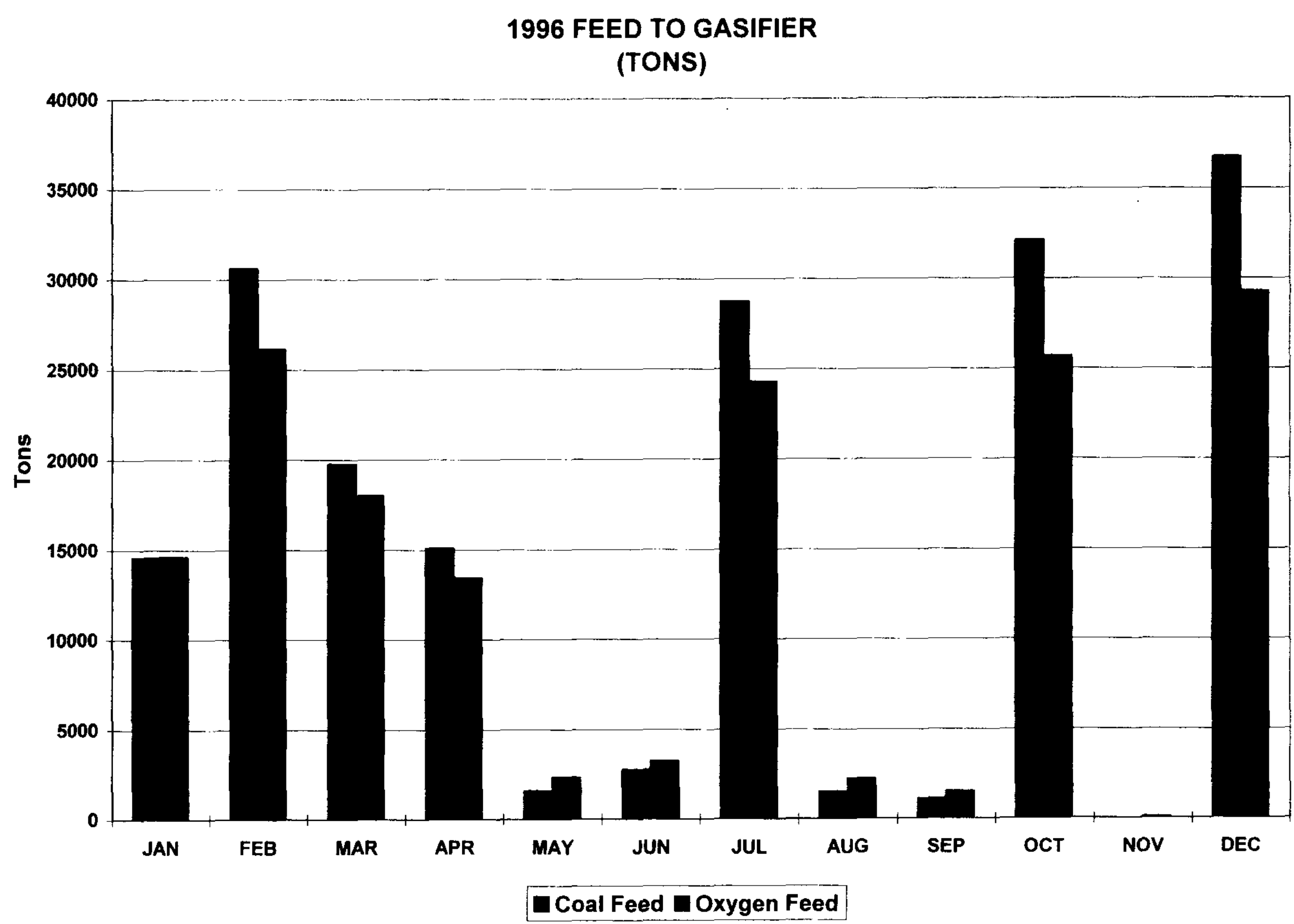


1996 SLAG PRODUCTION
(Mlbs - Moisture Free)
Mlbs
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
Slag Produced (Mlbs)

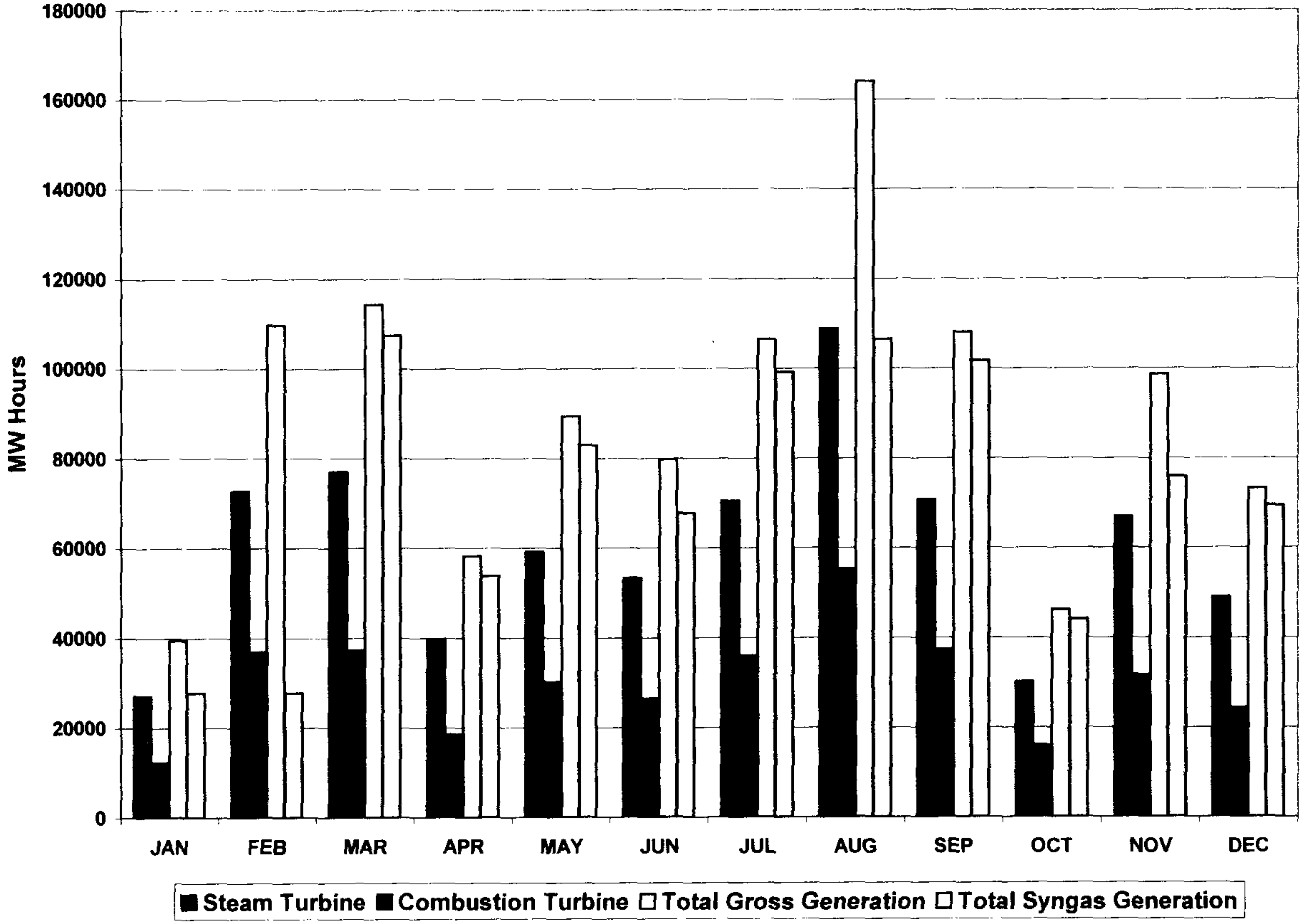

1996 DELIVERED SYNGAS
(MMBtu's)
MMBtu's
500000
450000
400000
350000
300000
250000
200000
150000
100000
50000
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
Syngas Delivered (MMBtu's)

1996 DELIVERED #1600 LB STEAM
(Mlbs)

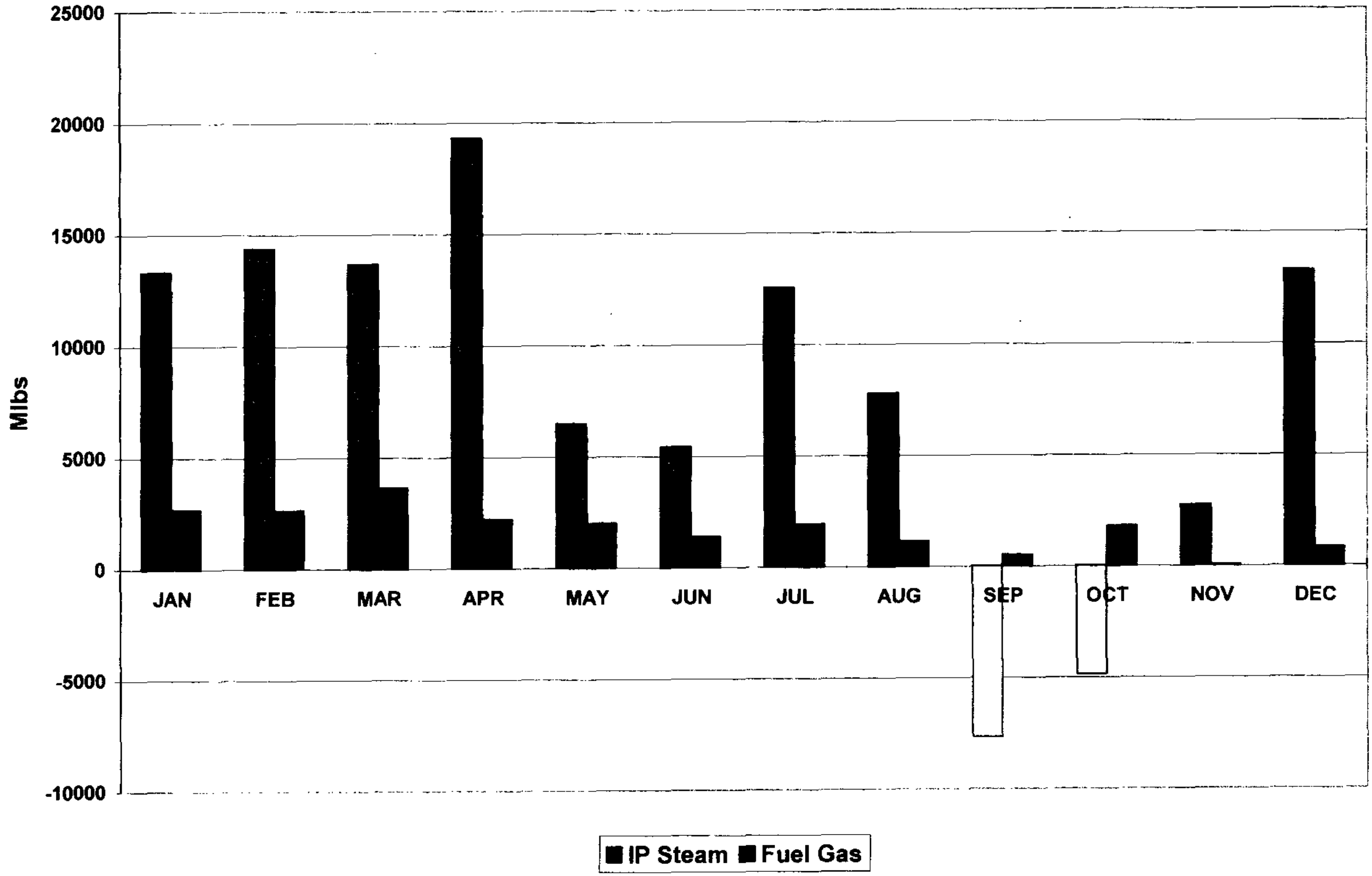



1996 FEED TO GASIFIER
(TONS)
Tons
40000
35000
30000
25000
20000
15000
10000
5000
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
Coal Feed
Oxygen Feed

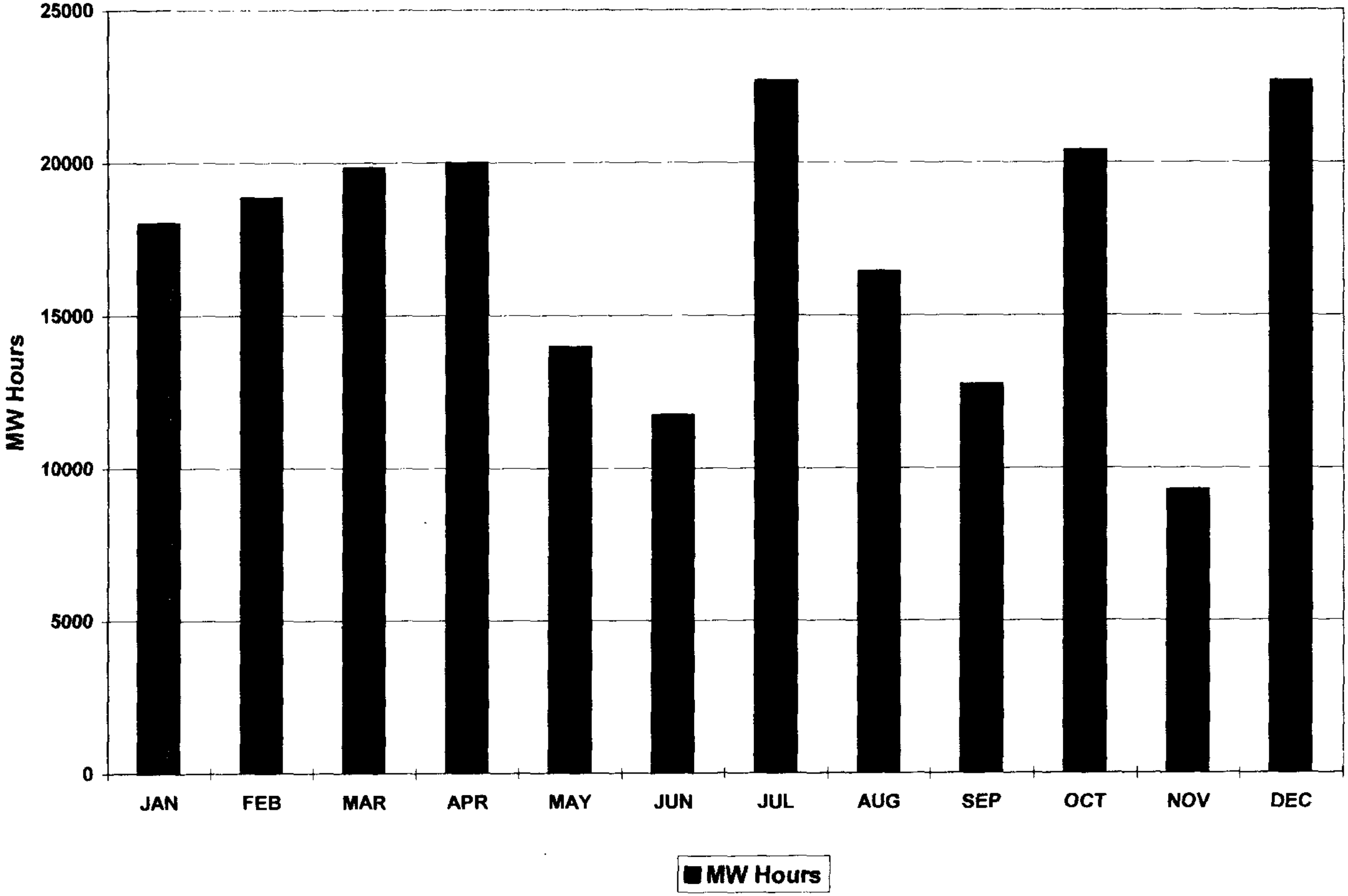
1996 Monthly Power Production

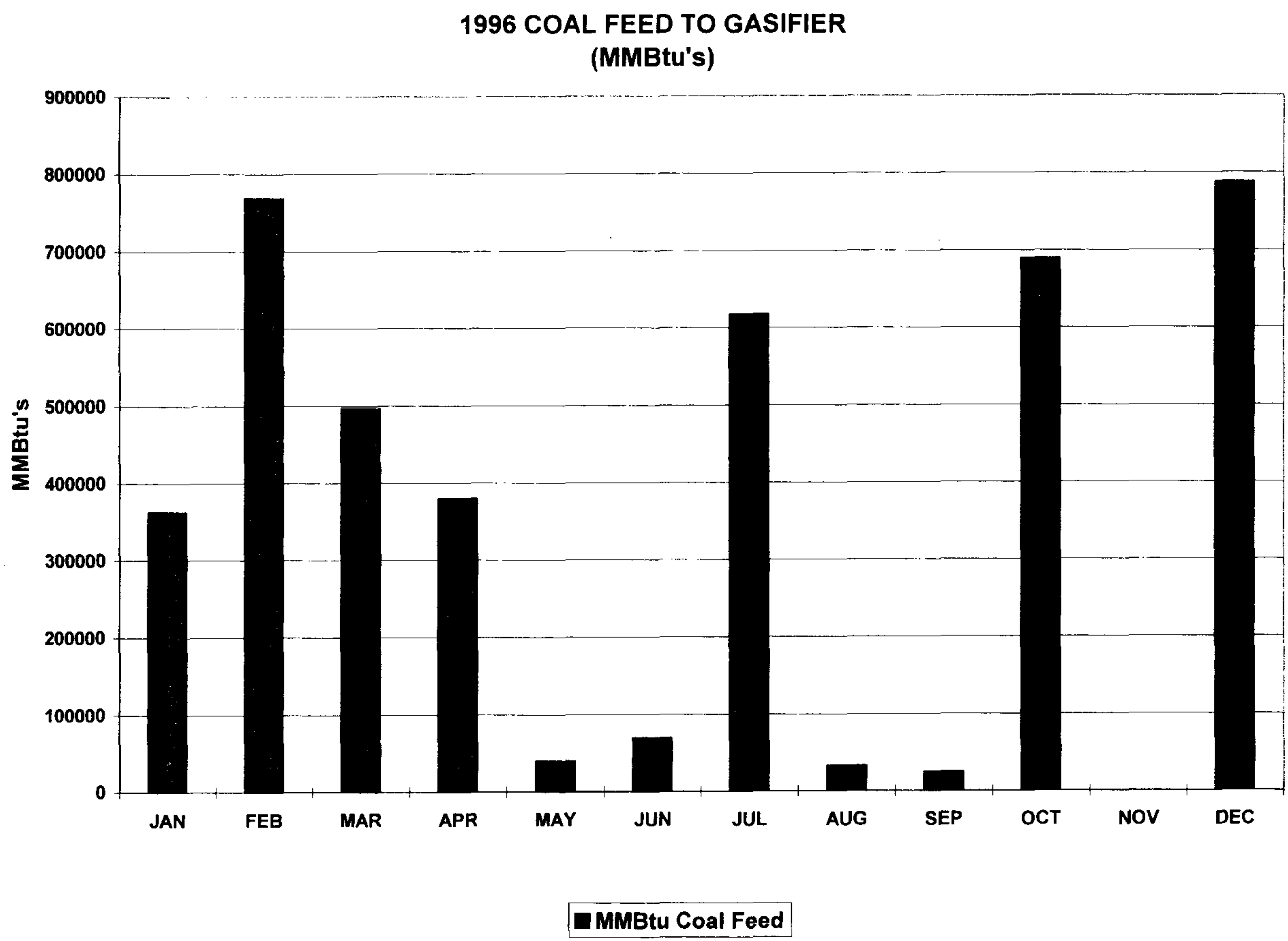


1996 ENERGY UTILIZATION (GASIFIER)
(Mlbs)

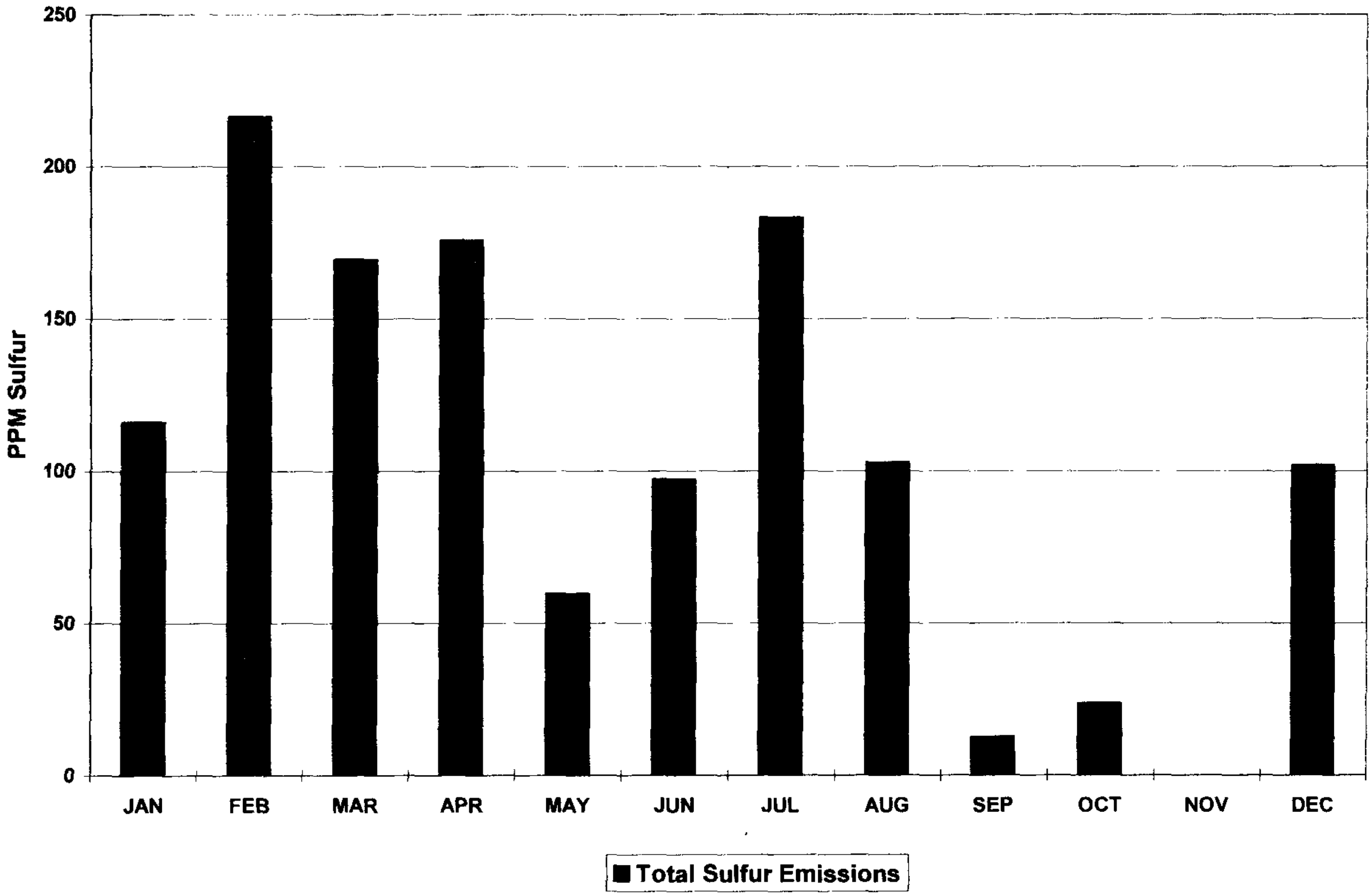


1996 ELECTRICAL ENERGY UTILIZATION GASIFICATION PLANT (MWH)




1996 COAL FEED TO GASIFIER
(MMBtu's)
MMBtu's
900000
800000
700000
600000
500000
400000
300000
200000
100000
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
MMBtu Coal Feed

1996 TOTAL SULFUR EMISSIONS (PPM as SULFUR)



1996 POUNDS OF SO2/MMBtu OF COAL FEED
(TOTAL REPOWERING EMISSIONS)